PUBLIC UTILITIES COMMISSION

DECOUPLING
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Reply Brief
of
Hawaiian Electric Company, Inc.
Hawaii Electric Light Company, Inc.
Maui Electric Company, Ltd.

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Goodsill Anderson Quinn & Stifel

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PUBLIC UTILITIES COMMISSION

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

In the Matter of the Application of

PUBLIC UTILITIES COMMISSION

Instituting a Proceeding to Investigate Implementing a Decoupling Mechanism for Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc. and Maui Electric Company, Limited.

DOCKET NO. 2008-0274

REPLY BRIEF OF HAWAIIAN ELECTRIC COMPANY, INC., HAWAII ELECTRIC LIGHT COMPANY, INC., AND MAUI ELECTRIC COMPANY, LIMITED

EXHIBIT "A"

AND

CERTIFICATE OF SERVICE

GOODSILL ANDERSON QUINN & STIFEL
A LIMITED LIABILITY LAW PARTNERSHIP LLP

THOMAS W. WILLIAMS, JR.
PETER Y. KIKUTA
DAMON L. SCHMIDT
Alii Place, Suite 1800
1099 Alakea Street
Honolulu, Hawaii 96813
Telephone: (808) 547-5600
Facsimile: (808) 547-5880

Attorneys for
HAWAIIAN ELECTRIC COMPANY, INC.,
HAWAII ELECTRIC LIGHT COMPANY, INC., and
MAUI ELECTRIC COMPANY, LIMITED

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BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

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REPLY BRIEF OF HAWAIIAN ELECTRIC COMPANY, INC., HAWAII ELECTRIC LIGHT COMPANY, INC., AND MAUI ELECTRIC COMPANY, LIMITED

This Reply Brief is respectfully submitted on behalf of HAWAIIAN ELECTRIC COMPANY, INC. ("Hawaiian Electric"), HAWAII ELECTRIC LIGHT COMPANY, INC. ("HELCO") and MAUI ELECTRIC COMPANY, LIMITED. ("MECO") (collectively, the "HECO Companies" or "Companies")[1] in response to the Opening Briefs ("OBs") filed September 8, 2009 on behalf of the Division of Consumer Advocacy of the Department of Commerce and Consumer Affairs ("Consumer Advocate"),[2] Haiku Design and Analysis ("HDA"), the State of Hawaii Department of Business, Economic Development, and Tourism ("DBEDT"), the Hawaii Renewable Energy Alliance ("HREA"), the Hawaii Solar Energy Association ("HSEA") and the Blue Planet Foundation ("Blue Planet").

I. DECOUPLING IS NEEDED NOW

A. NEED FOR AND BENEFITS OF DECOUPLING

The need for and benefits of decoupling, in general, and the HECO Companies and

[1] HECO Companies is abbreviated to "HECO" for purposes of the citations to the record.

[2] Consumer Advocate is abbreviated to "CA" for purposes of the citations to the record.

Consumer Advocate's Joint Decoupling Proposal ("Joint Decoupling Proposal"), in general, are addressed at length in the HECO Companies' Opening Brief[3] in Section I.C. See HECO OB at 6-22.

In summary, it is essential that the decoupling mechanism adopted in this docket include both (1) a sales decoupling component, which breaks the link between sales and electric revenue, and (2) a revenue adjustment mechanism ("RAM"). Decoupling revenue from sales (including changes in weather and economic upturns/downturns, costs of financing, the utility's credit rating, and other external variables) is intended to encourage energy efficiency and help the utility achieve its target revenue requirement in between rate cases. However, setting a target revenue requirement that does not change between rate cases under sales decoupling provides no compensation to the utility for increases in utility costs and infrastructure investment. Therefore, there is a need to allow increases in the target revenue requirement level each year. This is accomplished through the RAM.

The HECO Companies' immediate need for the sales decoupling component is driven by the trend of decreasing sales caused by energy efficiency, conservation, increasing amounts of customer-sited distributed generation ("DG"), and the poor economy, all of which threaten the financial well-being of the utilities when these sales decreases occur between rate cases.[4] See HECO OB at 8-9. The second component of the decoupling mechanism is the RAM, which compensates the utilities for increases in operating and maintenance ("O&M") costs and the return on and return of investments in infrastructure between rate cases. The immediate need for the RAM is driven by the increase in these costs related to maintaining and improving service reliability and normal inflation. See HECO OB at 8, 10-14.

[3] Opening brief is abbreviated as "OB" for purposes of citations to the record.

[4] And, in the case of HECO, when sales decrease below the test year level during the rate case test year.

The Joint Decoupling Proposal is not designed to specifically recover the lost earnings related to energy efficiency, but rather is designed to restore the utilities' cost of service revenue requirements in order to maintain the Companies' financial integrity and enable them to undertake and achieve the requirements and commitments in the revised Renewable Portfolio Standards ("RPS") law and in the Energy Agreement,[5] which triggered the changes in the RPS law. See HECO OB at 14-16 and Exhibit G ("Improving Financial Integrity").

State Energy Policy strongly supports substantially increasing the extent to which electricity is produced from indigenous renewable resources, and the availability of reliable electricity to support the needs of Hawaii's businesses, the military and residential consumers. These objectives require substantial capital expenditure programs by the utilities. Adding new plant will increase utility base revenue requirements. Obtaining the capital on reasonable terms will require financially sound utilities – which means that the utilities will have to be able to adjust base rates to recover the additional revenue requirements due to rate base additions (as well as the normal year-to-year cost increases to which all businesses are subject) without undue regulatory lag.

There are different ways to avoid that result. Electric utility rate structures could be changed so that revenues related to fixed costs are recovered through fixed charges – but that

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[5] The Energy Agreement among the State of Hawaii, Division of Consumer Advocacy of the Department of Commerce and Consumer Affairs, and the Hawaiian Electric Companies ("Energy Agreement" or "HCEI Agreement") was executed on October 20, 2008. The signatories include the Governor of the State of Hawaii, DBEDT, the Consumer Advocate, Hawaiian Electric, HELCO and MECO. The agreement, which arose out of the Hawaii Clean Energy Initiative ("HCEI"), provides that the HCEI Parties will pursue a wide range of actions with the purpose of decreasing Hawaii's dependence on imported fossil fuels through substantial increases in the use of renewable energy and implementation of new programs intended to secure greater energy efficiency and conservation. The Energy Agreement documents a course of action to make Hawaii energy independent, while recognizing the need to maintain the financial health of the HECO Companies in order to achieve that objective. Implementing legislation amending the RPS law, in the form of Act 155 (2009), has already been enacted. See HECO OB at 47-50 and Exhibit F.

"solution" does not enhance the overriding objective of reducing energy consumption through cost-effective energy efficiency measures, and does not address the need to increase base revenues from year-to-year. Electric utility rates could be reset each year in traditional rate cases that fully reflected forecast sales and costs – but that solution would impose an overwhelming burden on a regulatory system that already has numerous utility requests before it.

Decoupling (provided the mechanism includes both a sales decoupling and a compensatory revenue adjustment mechanism) supports the three key energy policy objectives by delinking revenues from sales through the sales decoupling mechanism, and by allowing annual adjustments in the utilities' base revenues (in between regularly scheduled rate cases). Thus, decoupling properly and effectively aligns regulatory financial outcomes (i.e., incentives) with State Energy Policy. See HECO OB at 20-22.

The benefits of decoupling extend beyond the need for decoupling. Sales decoupling, by breaking the link between sales and earnings, eliminates the financial penalty incurred by utilities through cost-effective energy efficiency measures and customer-sited distributed renewable energy generation that reduce sales. Thus, sales decoupling encourages utility support for energy efficiency measures and distributed renewable energy generation. See HECO OB at 8-10.

Decoupling also should reduce the frequency of rate cases. With decoupling (provided the mechanism includes both a sales decoupling and a compensatory revenue adjustment mechanism), a three-year rate case cycle is expected to be workable. Without decoupling, it has been assumed that a two-year rate case cycle would be required, but it is entirely possible that rate cases would be required in some instances even more frequently. (From a utility financial planning perspective, rate cases would have to be considered each year, at least on a contingency basis, even if they were filed less frequently, since there would be substantial uncertainty regarding sales revenues from year to year.) Traditional cost-of-service rate cases are costly to process, both in terms of the time and resources required by all of those involved in the cases (the utilities, the Consumer Advocate, and the Commission), as well as the cost in dollars (which for the utilities often exceeds $2 million). See HECO OB at 16-20.

The Consumer Advocate fully supports the Joint Decoupling Proposal. In its Opening Brief, the Consumer Advocate states that: "The provisions of this Joint FSOP are designed to achieve Hawaii's objectives regarding just and reasonable rates, administrative simplicity and efficiency and protection of the financial health of the utilities as HCEI Agreement implementation occurs." CA OB at 13; see also Tr. (7/1/09) at 700-01 (Awakuni).

The Consumer Advocate reiterates the points in support of decoupling in its Opening Brief:

> With HCEI implementation, it is expected that conservation and customer-sited renewable DG will displace increasing amounts of the HECO Companies' fossil-generated energy. To protect against the pervasive erosion of its energy sales revenues and the continuous cycling of rate cases that would be required to otherwise provide full fixed cost recovery, the RBA will stabilize the HECO Companies' margin revenues. One benefit of revenue stabilization is the protection of the HECO Companies' financial condition and ability to access capital markets on reasonable terms. Another benefit from decoupling revenue stabilization is the reduction in business risks faced by the HECO Companies after sales volume risks are shifted to ratepayers, which serves to rationalize a lower authorized return on equity for the utility in future rate cases. Next, it should be noted that decoupling is beneficial in eliminating the need in rate cases to accurately predict future test year sales volumes and revenues, because any inaccuracies in such predictions are self-correcting through the RBA account. Finally, by making the HECO Companies indifferent to changes in future sales volumes, decoupling removes any perceived business disincentive to fully support the deployment of renewable resources, DG or expanded conservation measures. In all of these ways, revenue decoupling and the RBA provision serve to complement the State's objectives set forth in the HCEI Agreement.
>
> Administrative efficiency and cost savings can be expected if decoupling is approved for the HECO Companies. These efficiency gains can be expected primarily as a result of less frequent general rate cases that tend to consume substantial resources and distract from other strategic initiatives before the

Commission in connection with the HCEI provisions.

CA OB at 14-15.

The Consumer Advocate also notes that: "Full decoupling of sales volumes from utility margin revenues is important to the goal of aligning utility incentives regarding sales volumes with the broader goals of the State to move away from fossil-fuel generated utility-supplied energy. Thus, it is apparent that the basic decoupling mechanism, as set forth in the RBA provision tariff and related administrative procedures documented within the Joint FSOP are entirely consistent with the State's objectives and should be approved." CA OB at 16.

The Consumer Advocate notes that "[t]he RAM provision is needed in addition to RBA, because the RBA will serve only to hold utility margin revenues constant between rate cases, providing no opportunity for recovery of any increasing costs to provide service." The Consumer Advocate further notes that the proposed RAM provision simplifies the "inherently complicated process" of estimating the HECO Companies' revenue requirements, and that the resulting estimates are intentionally conservative. "The combined effect of these RAM provision simplification and conservatism elements is intended to produce adequate revenue enhancement between formal rate cases to preserve the financial integrity of the HECO Companies in an administratively efficient manner (without annual rate cases)." See CA OB at 17-20. Thus, the "RAM provision will achieve Hawaii's objectives if it succeeds in reasonably estimating the HECO Companies' incremental revenue needs, so as to yield just and reasonable rates without the delay and cost associated with processing formal annual rate cases." CA OB at 21.

All of the parties support (or appear to support) sales decoupling. The other parties also appear to recognize that the decoupling provision adopted in this docket should include a mechanism to increase the net revenue target (i.e., target revenue requirement after excluding costs recovered or tracked through other mechanisms) between rate cases.

In its Opening Brief, Blue Planet states that: "Blue Planet supports the adoption of sales decoupling with a Revenue Adjustment Mechanism ('RAM') (together, 'decoupling mechanism') in this proceeding that meaningfully and effectively aids in the achievement of Hawaii's energy objectives." Blue Planet OB at 1.

In its Opening Brief, DBEDT states that: "DBEDT believes that a well designed decoupling will help achieve Hawaii's objectives. Decoupling helps remove the barriers to the utilities to aggressively promote and accommodate clean and renewable resources by ensuring utility cost recovery and reducing or eliminating regulatory lag." DBEDT OB at 5. DBEDT also states that it "believes that timely cost recovery is important to enable the HECO Companies to deliver on their commitments in the Energy Agreement that in turn supports the achievement of Hawaii's energy goals." DBEDT OB at 7.

HDA recognizes that "several factors are changing that could affect the ability of the utilities to earn reasonable returns on an ongoing basis without frequent rate cases under existing regulatory protocols", including the "absence of persistent increased revenue between rate cases, recently due to flat or declining sales and demand volume and prospectively guaranteed by decoupling, constitutes a change in the Hawaii regulatory climate that affects the utilities' ability to earn reasonable returns on equity." In addition, HDA recognizes that "[s]everal persistent factors are expected to depress the rate of sales and demand growth in the future compared to historical periods, including aggressive state policy goals and standards to increase energy efficiency and renewable generation (including generation on the customer side of the meter which would reduce sales)." <u>See</u> HDA OB at 14-16.

HAD further notes that: "Aside from any necessity for a RAM to provide sufficient utility revenues according to conventional ratemaking standards, the proposed RAM could serve to further several corollary objectives that have merit in improving regulatory efficiency", such as a "reduction in the frequency of general rate cases and, more generally, decreased regulatory administrative burden", and "[i]mproved utility financial condition". HDA OB at 17. HDA goes on to state that: "The HECO Companies assert that acute financial circumstances might require HECO to file back to back rate cases if its proposed RAM is not approved. HECO also testified that its bond ratings are could potentially be downgraded if its financial health is not improved. If true, these are significant assertions." HDA OB at 19 (footnote omitted).

The support of some of the parties for the sales decoupling component of decoupling is qualified by their desire to eliminate the fixed sales heat rate efficiency factor in the Energy Cost Adjustment Clause ("ECAC"). Similarly, the support of some of the parties for the RAM component of decoupling is qualified by their desire to directly link accomplishment of RPS goals or commitments in the Energy Agreement to the HECO Companies' receipt of revenues under the proposed RAM.

The HECO Companies and the Consumer Advocate have addressed these concerns through modifications already incorporated in the Joint Decoupling Proposal, as is addressed in subsequent sections of this reply brief. At the same time, the Companies are willing to continue the dialogue with the other parties regarding the linkage between accomplishment of RPS goals or commitments in the Energy Agreement to decoupling, as all parties will then be in a better position to address this issue in time for Hawaiian Electric's next rate case. See discussion in Section II.C.3 (HCEI Performance Metrics) of this Reply Brief.

The positions of the other parties with respect to the need for and benefits of decoupling are further addressed in Sections I.B, II.B.2 (Sales Decoupling), II.B.3 (Revenue Adjustment Mechanism), and II.B.4 (Other Decoupling Mechanisms) of this Reply Brief.

B. <u>HAIKU DESIGN PROPOSALS</u>

In HDA's Opening Brief, HDA recommends that the Commission "issue an interim decision and order in this docket to capture some immediate opportunities that could result from a prompt decision by the Commission. HDA recommends the interim decision and order approve the proposed revenue balancing account ("RBA") and RAM decoupling mechanisms to commence immediately for Hawaiian Electric, "contingent upon HECO's agreement not to file a 2010 test year rate case". The ECAC is also proposed to be modified either by adopting the deadband around the target heat rate as reflected in the Consumer Advocates and HECO Companies' FSOP or by allowing a straight pass through of actual fuel and purchased energy expenses. HDA OB at 9.

The implementation of the RAM mechanism is proposed to be in place for a pilot period of one year. For MECO and HELCO, HDA recommends that the Commission order the implementation of the RBA with interim decision and orders for MECO and HELCO in their 2010 test year rate cases which would provide "a current, reasonable determination of target authorized revenues". HDA OB at 7, n.5.

HDA further recommends that the Commission allow the continuation of this Decoupling proceeding to address remaining substantial issues such as "whether other alternatives, allocation methods, safeguard provisions, and/or incentive mechanisms should be implemented." HDA OB at 8. The continuation of the proceeding is presented as an additional opportunity for the Commission to further decide and examine if the RAM should be extended for Hawaiian Electric and implemented for MECO and HELCO and "craft appropriate methods to allocate decoupling and RAM adjustments by customer class, provide performance incentives, ensure customer benefits and/or provide incentives for the utilities to control costs." HDA OB at 8-9. An issue that is also proposed to be considered for the RAM extension during the continuation of the docket is a commitment by the Companies to a three-year rate case cycle "moratorium" in conjunction with a possible "z-factor" mechanism for abnormal or outlying circumstances. See HDA OB at 9, 39. Although HDA acknowledges that the instant docket may not be the best venue to review an HCEI master plan, it recommends that the Commission require the submission of a draft master plan by the end of the first quarter 2010 to understand "how the various elements of the Energy Agreement and HCEI initiatives will work together in order to proceed with approval of the individual components." HDA OB at 40.

The Companies generally support HDA's recommendations noted above for an immediate implementation of the RBA and RAM for Hawaiian Electric with the Companies' agreement that Hawaiian Electric will not file a 2010 test year rate case, the establishment of the RBA for MECO and HELCO, and the continuation of this Decoupling docket. However, the Companies do not support certain features of the recommendations which are discussed below.

Establishment of the RBA for the HECO Companies

In the opening briefs filed by the parties, no party objected to the establishment of the RBA for the HECO Companies as pointed out by the Consumer Advocate. See CA OB at 16. The RBA as proposed in the Joint Decoupling Proposal is conservative in design, simple and workable with filings and review procedures. Other advantages of the RBA are that it will make the Companies indifferent to changes in future sales volumes, will stabilize the Companies' revenues which will protect the Companies' financial condition, and will be beneficial in eliminating the need for rate cases. CA OB 14-15. HDA in its opening brief argues that the

RBA as proposed in the FSOP is superior to even its own decoupling proposal, providing "more transparency and accountability". HDA OB at 5.

If the Commission were to order the immediate establishment of the RBA as proposed in the Joint Decoupling Proposal for Hawaiian Electric, Hawaiian Electric target revenues will be based on a rigorously reviewed test year that is the most current possible, the 2009 test year.[6] It will also allow Hawaiian Electric to collect revenues for the remaining months in 2009 that align with the test year revenue requirement authorized in the 2009 Rate Case Interim Decision and Order.[7] And, if the Commission were to immediately order the establishment of the RBA for MECO and HELCO with the issuance of the interim decision and orders for their 2010 test year rate cases, as noted by HDA, "the sensitivity of the determination of the test year sales and demand forecasts as substantial contested issues" is eliminated. HDA OB at 8 n.7. The establishment of the RBA for the Companies is considered beneficial by all of the parties and part of the policy framework for achieving Hawaii's energy objectives. DBEDT OB at 6.

Establishment of the RAM for the HECO Companies

HDA recommends that the Commission order the immediate establishment of a RAM for Hawaiian Electric only if Hawaiian Electric agrees not to file a 2010 rate case. The RAM is proposed in the context of a "pilot" for a period of one year that will provide information for the Commission to determine if the RAM should be permanently adopted and continued as well as provide opportunities to examine more carefully other issues and concepts such as the allocation of decoupling and RAM adjustment by customer class. HDA OB at 7-8.

If the Commission orders the establishment of the 2010 RAM for Hawaiian Electric,

[6] The immediate establishment of the RBA will fulfill item 1 in Section 28 of the Energy Agreement, which states, "The revenues of the utility will be fully decoupled from sales/revenues beginning with the interim decision in the 2009 Hawaiian Electric Rate Case (most likely in the summer of 2009)."

[7] Interim Decision and Order in Docket No. 2008-0083, filed July 2, 2009.

along with an RBA effective immediately, Hawaiian Electric agrees not to file a 2010 test year rate case. However, the RAM should continue until interim rates become effective pursuant to an interim decision and order issued by the Commission in Hawaiian Electric's 2011 test year rate case.[8] Because of the structural regulatory lag that takes place during a test year, if Hawaiian Electric is not allowed to continue the RAM while fixing its revenues to the 2009 test year level, the Company will not be given an opportunity to reach its authorized rate of return. Also, by allowing the RAM to continue until interim rates become effective pursuant to an interim decision and order in Hawaiian Electric's 2011 test year rate case., a second RBA and RAM annual filing will take place, which may provide a better picture of how the RBA and RAM process actually works when fully implemented and ongoing.

To provide the parties with an indication of Hawaii Electric's commitment to file a 2011 test year rate case and to set an expected date for the issuance of an interim decision and order in the Hawaiian Electric 2011 test year rate case, Hawaiian Electric commits to filing its 2011 test year rate case application by August 16, 2010. Pursuant to Hawaii Revised Statutes ("HRS") § 269-16(d), an interim decision and order would be expected from the Commission within 10 or 11 months, depending on whether the evidentiary hearing has taken place. This would imply that an interim decision and order for the 2011 test year rate case would be expected in June or July 2011. Regardless of the Commission's decision on the RAM in Hawaiian Electric's 2011 test year rate case interim decision and order in that docket, the continuation of the RBA would not be affected, unless otherwise ordered by the Commission.

HDA also recommends that the RAM should not be approved for MECO and HELCO until, based on the information gathered during Hawaiian Electric's RAM pilot period, the

[8] As stated on page 2 of Exhibit C of the Joint Final SOP, revised June 25, 2009, with the implementation of the RBA and RAM, Hawaiian Electric will file a 2011 test year rate case.

Commission determines that the RAM should be approved for MECO and HELCO. The HECO Companies do not agree with this proposal. The RAM is needed in addition to the RBA because the RBA provides no opportunity for the Companies to recover any increasing costs to provide service. The RAM as proposed by the Consumer Advocate and the Companies conservatively simulates changes in cost and is expected to "impose cost management disciplined [sic] upon HECO Companies' management, while still providing a reasonable opportunity to recover inflationary increases in cost as well as increased capital investment so as to reduce the need for formal rate cases." CA OB at 19. If MECO and HELCO are not allowed to implement the RAM (along with the approval of the RBA upon the issuance of the interim decision and orders for their 2010 test year rate cases) they may require back-to-back rate cases, depending on the inflationary pressures that are experienced or forecasted for 2011. Also the Commission's decision regarding the Hawaiian Electric RAM pilot would most likely be issued in 2011 at the earliest. Even if it were determined sometime in 2011 that the RAM should be established for MECO and HELCO, MECO and HELCO may experience a number of months in 2011 during which their target revenues are held to 2010 test year revenue requirement levels. As a result, even if the RAM were then implemented immediately with the Commission's order, the opportunity to earn a reasonable return would be diminished considerably. However, if the RAM is allowed to be implemented in January 2011 for MECO and HELCO, the Commission could order that the RAM revenues be refunded (with interest) if it determines that the RAM should not have been implemented.

Except for DBEDT, HDA and the other parties do not object to the methodology used to calculate the RAM as proposed by the Consumer Advocate and the Companies in the FSOP. The development of the calculation of the RAM took place with many discussions and negotiations between the Consumer Advocate and the Companies. Also, the RAM calculation and its results were the subject of much discussion in the technical workshops and many information requests ("IRs") directed to the Companies. As one of the parties that watched the development and various changes to the RAM calculation as the docket proceeded, HDA states that it "appreciates, acknowledges and largely relies upon the examination of and improvements upon the proposed RAM by the Consumer Advocate and its consultants." HDA OB at 6. HDA also supports the establishment of the RAM as proposed in the Joint Final Statement of Position of the HECO Companies and Consumer Advocate, filed on May 11, 2009, revised on June 25, 2009, in a letter filed with the Commission, titled "Revised and New Exhibits for the Joint SOP" ("FSOP") for Hawaiian Electric, with its own proposed Revenue per Customer adjustment (HDA RPC) "intended to approximate the magnitude of inter-rate-case revenues that would occur with existing ratemaking conventions (without decoupling)" and as a "reasonable mechanism to serve in lieu of the RAM if the RAM is not approved or is suspended for any reason". Thus, the Companies urge the Commission to approve the RAM and its calculation as proposed by the Consumer Advocate and the HECO Companies in their FSOP.

<u>Continuation of the Proceeding</u>

HDA recommends that the Decoupling docket remain open to review (1) the pilot RAM implementation and to determine if the RAM should be continued, amended, or terminated, (2) what the impacts on decoupling are due to decisions made in other HCEI-related dockets, (3) alternatives to the RAM to improve the administration of the ratemaking process, and (4) refinements to decoupling such as methods to allocate decoupling and RAM adjustments to rate classes.

The Companies agree that the instant proceeding should be continued to include discussion regarding the topic of performance incentive mechanisms. In its Opening Brief, DBEDT proposed performance metrics for service reliability and for meeting net energy metering ("NEM") goals.[9] Blue Planet proposed a Clean Energy Utilization performance incentive mechanism which measures the annual improvement in percent of total energy requirements supplied by clean energy resources. Even the Companies proposed a service quality index benchmark for System Average Interruption Duration Index ("SAIDI") in their opening brief to address the Commission's concerns regarding service reliability if decoupling is implemented. These various performance metrics have not been discussed among the parties in any detail. With the continuation of the docket, the need for performance metrics and their design (if it were determined that they were needed) is an important topic that should be further investigated.

HDA's recommendation for the submission and review of an HCEI "master plan" is well-intentioned but should be rejected, since the instant docket is not an appropriate venue for such a review (as acknowledged by HDA). The proper venue to review demand and supply resources elements in the Energy Agreement is Clean Energy Scenario Planning ("CESP"). In the Order Initiating Investigation ("OII"), filed on May 14, 2009, the Commission opened Docket No. 2009-0108 to examine proposed amendments to the intergrated resource planning ("IRP") Framework ("IRP Framework")[10] as proposed by the HECO Companies, Kauai Island Utility Cooperative ("KIUC"), and the Consumer Advocate in a letter dated and filed on April 28, 2009. In the letter, the HECO Companies, KIUC, and the Consumer Advocate requested that

[9] The revised NEM performance metrics were those performance measures that remained after DBEDT removed metrics associated with Energy Agreement initiatives that are still pending Commission approval.

[10] The IRP Framework was adopted by the Commission by Decision and Order No. 11630 (May 22, 1992) ("D&O 11680") in Docket No. 6617, amending and reissuing the IRP Framework adopted in Decision and Order No. 11523 (March 12, 1992).

the a Clean Energy Scenario Planning Framework ("CESP Framework") be established to institute a ". . . planning process to develop generation and transmission resource plan options for multiple 20-year planning scenarios . . . [and] the development of a 5-year Action Plan based on the range of resource needs identified through the various scenarios analyzed." OII, page 2. The goal of the CESP that was agreed to by parties to the Energy Agreement (see Energy Agreement Initiative No. 33) is to develop such scenarios and action plans, "balancing how the utility will meet clean energy objectives, customers' expected energy needs, and protecting system reliability at reasonable costs under various scenarios."[11] The Commission role as proposed in the CESP Framework is to "determine whether the utility's CESP scenarios and CESP Action Plan represents a reasonable course for meeting the energy needs of the utility's customers, is in the public interest, is consistent with this Clean Energy Scenario Planning Framework, and provides strategic guidance for future utility planning to achieve Hawaii's clean energy future based on the HCEI Energy Agreement."[12] The decoupling docket was opened to "examine implementing a decoupling mechanism . . . that would modify the traditional model of rate-making for the HECO Companies by separating the HECO Companies' revenues and profits from electricity sales."[13] This docket's scope is very narrow as compared to the CESP Framework and should not be broadened as requested by HDA.

A possible schedule of activities to address issues noted above such as performance metrics is as follows:

(1) Technical workshop to be held before the end of the year on performance metrics;

(2) Review of the RBA and RAM filing process to take place with parties (either

[11] OII, Exhibit A, Attachment 1 at 4.
[12] Id.
[13] OII, Docket No. 2008-0274, filed October 24, 2008 at 1.

meeting or conference call) sometime in March/April (the RAM for 2010 is proposed to be filed by March 31, 2010);

(3) Review of customer education communications to take place with parties (either meeting or conference call) sometime in early June (Billing of the RBA and RAM is proposed to commence on June 1, 2010); and

(4) Filing of statements of position by the parties no later than June 30, 2010, so they can be "incorporated" or referenced in the Hawaiian Electric 2011 rate case.

Summary

As explained above, the immediate issuance of an interim decision and order approving the RBA and RAM for the HECO Companies along with the continuation of this docket will allow the parties more time to gather and share information regarding the actual decoupling and RAM implementation experience and to review and develop appropriate metrics that would enhance decoupling and the RAM in the future.

II. ISSUES

A. PREHEARING ORDER

There are ten explicitly stated issues in this docket.[14] The record in this docket addresses all of these issues, and fully supports approval of the Joint Decoupling Proposal.

1. Whether the joint proposal or any separate proposals that are submitted by the HECO Companies, the Consumer Advocate or other parties are just and reasonable?

The Joint Decoupling Proposal is just and reasonable. The proposal (1) is thorough, complete and well thought out, (2) is relatively simple and straight forward, (3) from a customer standpoint, is relatively conservative, and (4) addresses the problems that it was

[14] See Order Approving, with Modifications, Stipulated Procedural Order Filed on December 26, 2008, filed January 21, 2009 ("Procedural Order"), Exhibit 1, at 2-4.

intended to address, without significant unintended consequences.

The hybrid RAM[15] proposed by the HECO Companies and the Consumer Advocate is neither novel nor untested. A variety of approaches to RAM design have been used in California since the inception of decoupling, but the hybrid approach has been the most common over the years.

The Consumer Advocate's Consultant testified that the Consumer Advocate was successful in "structuring an RBA and RAM agreement that was protective of the public interest, conservative in exposure rate payers would face to increasing revenue requirements, and designed in a way that would be administratively practical. A process that would result in a single annual filing for each of the companies. Hopefully a filing that would avoid one or more full-blown rate case proceedings." Tr. (6/29/09) at 94 (Brosch). In addition, Mr. Brosch testified that the RBA mechanism tracks changes in the margin recovery through sales, and the RAM mechanism is intended to simulate changes in cost and estimating what the revenue requirement would be like in the absence of a rate case. Tr. (6/29/09) at 96 (Brosch).

Mr. Brosch also testified that the joint decoupling proposal of the HECO Companies and Consumer Advocate was a reasonable balance for the HECO Companies at this time, built on the premise that historical trends of recovering costs through increased sales was reversing. Without a different approach to revenue requirements, Mr. Brosch felt that back-to-back-to-back rate cases would occur for the HECO Companies. Tr. (6/29/09) at 95 (Brosch).

Sales decoupling and revenue adjustment mechanisms have been used in many

[15] The Joint decoupling Proposal is essentially a hybrid RAM, in which operations and maintenance ("O&M") expenses are escalated using a formula that includes inflation or input cost escalators (a formulaic approach), and rate base is escalated based on a trended forecast and actual balances. The term "hybrid" refers to the combination of formulaic and forecast approaches to derive the annual change in target revenue requirements.

jurisdictions without major difficulties. The Joint Decoupling Proposal takes advantage of the lessons learned from some of these jurisdictions to reduce the possibility of problems in implementation. However, there may still be concerns by the Commission regarding the risk of unintended consequences resulting from the move to a new ratemaking regime in Hawaii. To reduce this risk, the Joint Decoupling Proposal includes a number of "exit ramps", which provide the Commission, the Consumer Advocate, and the Companies the ability to review the performance of revenue decoupling and take steps to correct, suspend, or terminate the mechanism:

(1) Decoupling will be reviewed anew in Hawaiian Electric's 2011 test year rate case;

(2) The Commission may review the decoupling mechanism at any time if it determines that the mechanism is not operating in the interests of the ratepayers;

(3) The utility or the Consumer Advocate may also file a request to review the impact of the decoupling mechanism; and

(3) The Commission may unilaterally discontinue the decoupling mechanism if it finds that the public interest requires such action.

Under the Joint Decoupling Proposal, the Commission may unilaterally discontinue the decoupling mechanism if it finds that the public interest requires such action. However, it should be recognized that the public interest consists of both a short-term and long-term interest. Therefore, while during the short-term electricity rates may increase should electricity sales lag behind test year sales, the long-term benefits have great value to utility customers and the Hawaii community as a whole.

The only party that proposed an alternative to the RAM was HDA, which presented a Revenue per Customer ("RPC") mechanism. As described by HDA's representative in its closing statement, its intent was to offer a "vanilla" alternative to the RAM in the form of an RPC mechanism, which was not intended to address financial integrity issues such as regulatory lag. Thus, HDA did not take the position that the RPC mechanism should be adopted instead of the RAM.

The HECO Companies have addressed the reasons why the RAM was definitely preferable to an RPC mechanism in the report entitled *Revenue Decoupling for Hawaiian Electric Companies* ("PEG Report") prepared by their consultant, Pacific Economics Group, LLC (", in their Comments on the NRRI Scoping Paper (which was filed February 20, 2009) in their Initial Statement of Position on HDA's Decoupling Proposal (filed March 30, 2009), and in their responses to IRs, as summarized in Section II.B.5 and Exhibit A to this Reply Brief.

As is indicated above, the RPC mechanism proposed by HDA does not attempt to address the objectives of the RAM to partially recover, between rate cases, the increases in costs that are fixed in the short term due to inflation, changes in utility output, and investments in utility infrastructure and, thus, to help maintain the financial health and integrity of the utility.

RPC mechanisms are commonly employed by natural gas local distribution utilities (LDCs), where a large portion of fixed costs are tied directly to, and vary with the number of customers. The HECO Companies' fixed costs are not related to the number of customers. Thus, as a means to help ensure that the Companies remain financially healthy between rate cases, the RPC methodology will not perform nearly as well as the RAM.

To avoid financial attrition, utilities operating under RPC freezes file rate cases more frequently. This raises regulatory cost and can compromise utility cost performance. A RAM that provides relief for inflation as well as customer and activity growth makes it possible to simultaneously reduce regulatory cost and improve utility performance. That is why most RAMs that have been implemented in the U.S. and other countries over the years have not employed a RPC freeze.

2. Whether the decoupling mechanism(s) will result in accelerating the addition of new, clean energy resources in the HECO Companies' systems, while giving the HECO Companies an opportunity to achieve fair rates of return?

Traditional utility ratesetting contains a disincentive to energy efficiency and customer sited renewable energy. The Joint Decoupling Proposal is designed to overcome this disincentive that is inherent under traditional ratemaking (where prices are fixed in rate cases, and revenues vary with sales).

The disincentive stems from the manner in which utilities operating under traditional ratemaking recover their fixed costs. Typically, utilities (like the HECO Companies) recover their fixed costs partially through fixed charges, such as customer charges, and partially through volumetric charges such as energy (or per kilowatt-hour "kWh") charges. This rate design works well when kWh sales increase from year to year. The increase in sales increases revenues to cover the fixed costs approved by regulators in the last rate case and also compensates the utility for (1) cost escalation due to needed expansion of system infrastructure, service volumes, and, of course, inflation, and (2) maintaining an adequate return on rate base to attract investors.

However, if sales are stagnant or are on a long-term decreasing trend, the falling revenues fail to fully recover fixed costs. This leads to an erosion of utility earnings and financial performance, and a reduction in the utility's capacity to invest in needed infrastructure to support reliability and public policy priorities such as renewable energy. Under traditional ratemaking the conventional solution to this situation is to initiate a rate case. However, since rate proceedings take, usually, at the very least, many months to adjudicate, it is difficult for the utility to maintain financial health. Under these conditions, it is not unusual for utilities to need to file for rate cases in quick succession in an effort to reset their rates to compensate for falling sales and increasing costs.

Conservation, energy efficiency, and customer-sited renewable generation contribute to falling sales. While these measures move the state toward energy goals that all stakeholders support, the erosion of electricity sales and revenues results in significant negative financial impacts to the utilities. If the utilities' revenues were not linked to sales, the disincentive to conservation, energy efficiency, and renewable generation could be eliminated. The HECO Companies' revenue decoupling proposal removes that disincentive.

Sales decoupling supports energy efficiency and customer-sited renewable generation, initiatives that have broad community support due to their positive impacts on oil independence, energy self-sufficiency, and energy security. Sales decoupling coupled with a compensatory RAM also provides the electric utilities with the financial ability to preserve a stable electric grid to minimize disruption to service quality and reliability and retain the capacity to invest in infrastructure necessary to achieve an independent renewable energy future.

Major stakeholders, including the Governor of the State of Hawaii, the Division of Consumer Advocacy of the State of Hawaii Department of Commerce and Consumer Affairs, and the HECO Companies, signed the landmark Energy Agreement in October 2008 committing to support revenue decoupling because of its significant potential contribution to the public benefit <u>and</u> to support the need for a financially sound electric utility that is necessary to achieve the system reliability objectives and independent renewable future. The Energy Agreement states that: "[W]e recognize the need to assure that Hawaii preserves a stable electric grid to minimize disruption to service quality and reliability. In addition, we recognize the need for a financially sound electric utility. Both are vital components for our achievement of an independent renewable energy future."

The strong link between a utility's financial strength and ability to attract capital on reasonable terms, and the utility's ability to aggressively add renewable energy resources to its system, has been documented in a number of proceedings and is recognized in the RPS law and the long-standing IRP Framework.

HRS § 269-94 provides that: "The public utilities commission may provide incentives to encourage electric utility companies to exceed their renewable portfolio standards or to meet their renewable portfolio standards ahead of time, or both." In addition, HRS § 269-95 addresses ratemaking structures that "ensure that the electric utility companies' opportunity to earn a fair rate of return is not diminished . . . ."

Paragraph II.B.5 of the IRP Framework provides as one of its governing principles that "[i]ntegrated resource plans shall take into consideration the utility's financial integrity, size, and physical capability."

Several parties have taken the position that there should be a direct link between the revenues received by the HECO Companies under the RAM, and their achievement of the objectives of their commitments in Energy Agreement. In effect, they are attempting to make the availability of the RAM the *quid pro quo* for the commitments. They have then proposed various metrics to attempt to measure achievement of the commitments, and have arbitrarily proposed reductions in the RAM revenues if the metrics are not achieved.

The concerns with the "HCEI Performance Metrics" proposals submitted during the course of the proceeding have been thoroughly documented, most recently in pages 76 to 81 of the HECO Companies' Opening Brief, and in Section II.D.2 of this Reply Brief. The

Companies' position has been that tying a "performance-based" indexing of HCEI goals to the RAM is not necessary, because (1) the RAM will be reviewed in each of the HECO Companies' rate cases subsequent to their respective 2009 test year rate case in which decoupling will be implemented, (2) there are mechanisms in the Joint Decoupling Proposal for the review and discontinuance, if appropriate, of the decoupling mechanism, and (3) the RPS Framework includes de facto enforcement and penalty provisions should the Companies fail to make adequate progress toward the renewable energy goals.

Noting that there is very little agreement among the parties regarding the performance metric issue, HDA has proposed that the Commission take advantage of immediate opportunities by issuing an interim decision and order in the instant docket approving the RBA and RAM for Hawaiian Electric and continuing the decoupling proceeding to address the performance metric issue along with other decoupling issues.[16]

As discussed above in Section I.B, the Companies generally support HDA's proposal. Because of the strong desire of some of the parties to directly link accomplishment of RPS goals or commitments in the Energy Agreement to the HECO Companies' receipt of revenues under the proposed RAM, the Companies are willing to continue the dialogue with the other parties regarding the linkage between accomplishment of RPS goals to decoupling as long as both award and penalty provisions are included in the performance incentive mechanism and the performance incentive mechanism is consistent with the RPS law as amended by Act 155 (2009). Therefore, the HECO Companies now generally support the adoption of some type of broad-based clean energy[17] performance incentive mechanism in this proceeding, subject to agreement on the specific mechanism and its details. Further discussion of the process envisioned to

[16] HDA OB at 7-8.
[17] Defined as "Renewable Electrical Energy", under HRS § 269-91.

accomplish this is provided in the Section II.C.3 (HCEI Performance Metrics) of the Reply Brief.

3. What should be the scope of and elements to be included in the decoupling mechanism?

The Joint Decoupling Proposal identifies the appropriate scope of and elements to be included in the decoupling mechanism. The key components of the Joint Decoupling Proposal are addressed in Section II.B of this Reply Brief.

4. How will decoupling impact the utilities, their customers, and the clean energy market?

The need for, benefits of and impacts of decoupling from the perspective of the HECO Companies and its customers are addressed in Sections I.C and II.C of the Companies' Opening Brief and Section I.A of this Reply Brief.

The sales decoupling mechanism establishes a target revenue requirement (i.e., sales revenue forecast used in the rate case being used as the base year). The impact of a sales decoupling mechanism on customers' rates depends on whether electric sales revenues are higher or lower than the target revenue requirement. Mr. Freedman testified that:[18]

> The decoupling part of the process itself is revenue neutral. Sales go up; sales go down. What we're trying to do is make sure we have a balance of recovery of fixed costs, just as we would with more frequent rate cases. But we are removing some bad disincentives and we're also still providing some value in reduced risk to the company. It can be a net gain in terms of by assuring the company of recovery of revenues.

The RAM is designed to adjust the target revenue requirement level each year in order to compensate utilities for changes in O&M costs and the return on and return of investments in infrastructure between rate cases, which results in a rate increase in the absence of deflation.

Annual or biannual rate cases for the Companies are an alternative means to obtain the

[18] Tr. (7/1/09) 721-22 (HDA's closing statement).

needed revenue requirement escalation under a decoupling plan without a RAM. As previously discussed, this approach would involve a high level of regulatory cost at a time when the implementation of the new RPS enacted by Act 155 (2009) and the Energy Agreement will be raising a host of new issues meriting regulatory oversight, and there is also concern that annual rate cases would not be sufficiently compensatory.

From a customer standpoint, the overall impact on prices would generally be the same, whether price increases result from decoupling or from rate cases. However, decoupling does include the potential to reduce a utility's cost of common equity (from what it would have been without decoupling), and to reduce rate case costs. These cost reductions would result in somewhat lower rates with decoupling, at least in the long run.

Rates could be lower under the rate case model (without decoupling) if regulatory lag prevents the utility from implementing rates that fully cover its costs. Such a result, however, would severely damage the utility's financial integrity and ability to attract capitol - and would be detrimental to both the utility and its customers.

5. Which issues and details regarding the implementation of the decoupling mechanism(s), including the determination of any revenue target, should be taken up in the context of individual rate case proceedings of HECO, HELCO?

The revenue target should be determined in the individual rate proceedings.

6. Whether any cost tracking indices proposed for use in estimating revenue adjustment calculations can be expected to determine just and reasonable revenue adjustments on an on-going basis, accounting for the differences between the revenue requirement amounts determined in each utility's last rate case and: (a) The current cost of operating the utility; (b) Return on and return of ongoing capital investment; and (c) Any

changes in State or federal tax rates?

The proposed RAM component of the Joint Decoupling Proposal follows cost of service, with a conservative "bias".

7. Whether any earnings monitoring/sharing, service quality provisions, or any other adjustments or considerations are appropriate to implement as part of the decoupling methodology in order to calculate ongoing revenue adjustments that are just and reasonable?

The Joint Decoupling Proposal includes and includes an Earnings Sharing Revenue Credit Mechanism (see Section II.B.5 of this Reply Brief) which would, by sharing any surplus earnings with customers, weaken incentives to take extreme cost containment measures that could jeopardize quality (see Section II.D.1 of this Reply Brief).

8. Whether any provisions for administrative procedures (e.g., utility filings, decoupling tariffs, deferral accounting provisions, customer notice provisions, planned review/audit procedures and any appeal or hearing provisions) are appropriate, necessary and sufficient to ensure that post test year decoupling adjustments are fair and reasonable?

The Joint Decoupling Proposal includes the appropriate tariff provisions for the implementation of the RBA and the RAM.

9. How many years should the decoupling/attrition revenue mechanism remain in place for each of the utilities before the next rate cases are to be filed and under what conditions can the utility, the Commission or other parties initiate formal rate proceedings outside of such rate case intervals?

The Joint Decoupling Proposal is subject to review within a relatively short period:

(1) Decoupling will be reviewed anew in Hawaiian Electric's 2011 test year rate case;

(2) The Commission may review the decoupling mechanism at any time if it determines that the mechanism is not operating in the interests of the ratepayers;

(3) The utility or the Consumer Advocate may also file a request to review the impact of the decoupling mechanism; and

(4) The Commission may unilaterally discontinue the decoupling mechanism if it finds that the public interest requires such action.

Under the Joint Decoupling Proposal, the Commission may unilaterally discontinue the decoupling mechanism if it finds that the public interest requires such action. However, it should be recognized that the public interest consists of both a short-term and long-term interest. Therefore, while during the short-term electricity rates may increase should electricity sales lag behind test year sales, the long-term benefits have great value to utility customers and the Hawaii community as a whole.

The Joint Decoupling Proposal would require the HECO Companies to file rate cases on a three-year cycle[19] to reset the target revenues, but would not prohibit a utility from filing a rate case sooner.

10. What accounting and regulatory reporting provisions are necessary to implement any decoupling provisions in a manner that will ensure reasonable definition, isolation and recovery of the types of costs that are to be separately tracked and charged to customers through other cost recovery mechanisms, such as: Renewable Energy Infrastructure Program/Clean Energy Initiative, Energy Cost Adjustment Clause, Purchased Power, Demand Side Management, and other surcharge mechanisms?

The Joint Decoupling Proposal includes the appropriate tariff provisions for the implementation of the RBA and the RAM. The Joint Decoupling Proposal relies upon

[19] To stagger the rate cases and to allow review of the decoupling mechanism within a relatively short period, the next rate case for HECO would file a 20011 test year rate case. Either HELCO or MECO would file a 2012 test year rate case, and the non-filing company would file a 2013 test year rate case.

readily available, verifiable data, and is consistent with existing reporting and tracking mechanisms.

B. JOINT DECOUPLING PROPOSAL

1. Joint Decoupling Proposal

The Consumer Advocate and the HECO Companies submitted their original Joint Decoupling Proposal with their Statement of Position filed March 30, 2009. The current Joint Decoupling Proposal was described in the Joint Final Statement of Position of the HECO Companies and Consumer Advocate (filed May 11, 2009) ("Joint FSOP") and Exhibits A – C, as modified in the letter from the HECO Companies and the Consumer Advocate to the Commission dated and filed June 25, 2009 (revised Attachment 7 to Exhibit C), and letter from the HECO Companies to the Commission dated and filed July 13, 2009 (Attachment 7 at 4).[20]

The current Joint Decoupling Proposal is described in detail on pages 26 to 46 of the HECO Companies' Opening Brief. The key components include:

(1) a sales decoupling mechanism, which would be implemented through a RBA tariff provision (see HECO OB at 3);

(2) a RAM, consisting of an O&M RAM component and a Rate Base RAM component, which is in the form of a RAM tariff provision (see id.);[21]

(3) an Earnings Sharing Revenue Credit Mechanism, which would be implemented through a RBA tariff provision (see id.);

(4) consumer protection features included in the RAM tariff provision (in addition to the Earnings Sharing Revenue Credit Mechanism, see HECO OB at), which would include a provision for Major Capital Projects Credits[22] (see HECO OB at) and require the HECO Companies to provide a detailed status report on selected clean energy initiatives as part of the Companies' testimonies and exhibits in the next cycle of rate cases (see id.

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[20] See HECO OB at 54-55 for a description of the modifications.

[21] The revenue adjustments resulting from the RAM tariff provision also would be implemented through the RBA tariff provision.

[22] See Attachment 7, page 4 of the Companies' *Questions from Panel Hearings Held on June 29 to July 1, 2009* Letter to the Commission, filed July 13, 2009.

at 3-4);[23] and

(5) a proposal to establish deadbands and provisions to reset the fixed sales heat rate factor in the ECAC (see id. at 4 and Exhibit C).[24]

As noted in the Opening Brief, the Joint Decoupling Proposal evolved during the course of this proceeding based on (1) extensive review and discussion between the Consumer Advocate, the HECO Companies and their consultants, (2) input from the other parties, and (3) questions and hypotheticals posed by the Commission and its consultant. See HECO OB at 4. As a result, the proposal (1) is thorough, complete and well thought out, (2) is relatively simple and straight forward, (3) relies upon readily available, verifiable data, (4) is consistent with existing reporting and tracking mechanisms, (5) follows cost of service, with a conservative "bias", (6) contains built-in customer protections, (7) is subject to review within a relatively short period, (8) from a customer standpoint, is relatively conservative, and (9) addresses the problems that it was intended to address, without significant unintended consequences.

The Consumer Advocate's consultant testified that the Consumer Advocate was successful in "structuring an RBA and RAM agreement that was protective of the public interest, conservative in exposure rate payers would face to increasing revenue requirements, and designed in a way that would be administratively practical. A process that would result in a single annual filing for each of the companies. Hopefully a filing that would avoid one or more full-blown rate case proceedings." Tr. (6/29/09) at 94 (Brosch). In addition, Mr. Brosch testified that the RBA mechanism tracks changes in the margin recovery through sales, and the RAM mechanism is intended to simulate changes in cost and estimate what the revenue

[23] See Exhibit E, page 3 of the Companies' and the Consumer Advocate's FSOP, filed May 11, 2009. The specific HCEI initiatives proposed to be included in the status report were: new NEM (MW and customer), the amount of new renewable energy purchased under Feed-in-Tariff ("FIT") when effective, and the increase in other renewable/non-fossil-based generation.

[24] The Deadband for HECO was proposed in the HECO Companies and Consumer Advocate's May 11, 2009 FSOP. Deadbands for MECO and HELCO were proposed in the HECO Companies' *Revised and New Exhibits for the Joint FSOP*, filed June 25, 2009.

requirement would look like in the absence of a rate case. See id. at 96.

Mr. Brosch testified that the joint decoupling proposal of the HECO Companies and Consumer Advocate was a reasonable balance for the HECO Companies at this time, built on the premise that historical trends of recovering costs through increased sales was reversing. Without a different approach to revenue requirements, Mr. Brosch felt that back-to-back-to-back rate cases would occur for the HECO Companies. Id. at 95. One of the primary drivers of the Consumer Advocate's support of the proposed decoupling mechanism is less frequent rate cases. See id. at 99-101.

Potential Alternative Provisions

In its Opening Brief, the HECO Companies also identified alternatives that could be reasonably included in the proposal to address certain concerns raised during the panel hearings, including (1) a Reliability Benchmark provision (see HECO OB at 86-89 and Exhibit D), (2) possible modifications to the RAM rate base component (see HECO OB at 97-99 and Exhibit B), and (3) an alternative to allocating the RBA to two customer "classes" (see HECO OB at 89-94). The modification to the RAM rate base component would require quarterly filings of the RBA to update the RAM rate base component.

The HECO Companies have not revised their Joint Decoupling Proceeding to formally incorporate these possible alternatives. They are being provided as acceptable modifications to address possible concerns raised during the course of this proceeding. The tariff provisions filed as a result of the Commission's decision in this proceeding will incorporate any changes required by the decision.

2. Sales Decoupling

All of the parties support (or appear to support) sales decoupling. Several of the parties recommended, however, that the fixed sales heat rate efficiency factor ("fixed heat rate") in the ECAC be eliminated, because the fixed heat rate can be a disincentive to acquire and/or dispatch renewable energy generation. See HECO OB at 71-73 and Exhibit C.[25]

The Joint Decoupling Proposal addresses this concern by proposing (2) a heat rate deadband around the fixed heat rate target, within which fuel costs would pass through at the actual achieved heat rate(s) , and (2) re-setting of the target heat rate(s) when system generation changes cause the expected heat rate(s) to fall outside of the the target(s). The deadbands for Hawaiian Electric, and MECO's Lanai and Molokai Divisions, would be +/- 50 Btu/kwh sales. The deadbands for HELCO and MECO's Maui Division would be +/- 200 Btu/kwh sales. See HECO OB at 73-76 and Exhibit C.

This issue is addressed at some length in the Opening Briefs of the other parties, and responses to points raised in the other briefs are included in Section II.C of this Reply Brief. In summary, the deadband proposal adequately addresses the concerns raised by the other parties, without sacrificing the benefit of having the fixed heat rate target efficiency factor.

Rate Design

DBEDT contends that cost-based rate design could help reduce or minimize the lost fixed cost recovery and therefore help reduce the need for or the impact of a decoupling mechanism.[26] DBEDT's suggestion to minimize the amount of the decoupling adjustment is misplaced. In fact, revenue from rate design and revenue from a decoupling adjustment combine to achieve the target revenue. Decoupling can be viewed as a necessary complement to rate design.

Rate design that is just targeted at recovering fixed costs when volume drops would not

[25] The reason for having a fixed heat rate (or fixed heat rates by fossil fuel type, as is proposed and stipulated to in pending 2006 and 2007 test year rate cases for the HECO Companies) has been addressed in recent rate cases. See also HECO response to NRRI Appendix 2 Question #3; CA responses to PUC-IRs-62 and -63.

[26] DBEDT OB at 41.

be deemed to sufficiently encourage energy conservation or customer sited DG. For example, inverted residential rates (as proposed for all of the HECO Companies) result in a greater loss of revenues per reduction in kWh sales than levelized rates. Lower demand charges for standby service, as implemented in Docket No. 2006-0497, result in a greater loss of revenues when DG customers adopt standby rates than do higher demand charges for such service.

The HECO Companies also have improved their cost-based rate design in recent rate cases by better aligning the customer-related, energy-related, and demand-related costs with proposed customer, energy, and demand charges.[27] The HECO Companies will continue to better align charges with costs and improve rate design in future rate cases. Under the decoupling proposal, the HECO Companies will have general rate cases on a regular cycle, which will create regular opportunities for the Commission to review rate design and related issues. DBEDT's recommendation,[28] that the Commission initiate a generic docket to investigate rate design and rate re-structuring, is unnecessary if the decoupling proposal is approved.

3. Revenue Adjustment Mechanism

The RAM Provision is designed to re-determine annual utility authorized base revenue levels, thus recognizing estimated changes in the utility's cost to provide service. If it is determined that annual utility Authorized Base Revenues should be decreased or increased, then the RAM Revenue Adjustment level applicable within the RBA Provision will be adjusted as set forth in the RAM Provision. The RAM Revenue Adjustments implemented under the RAM Provision will escalate and update the Company's approved base revenue requirement, reduced

[27] See the proposed rate designs in Docket No. 04-0113 (HECO test year 2005), Docket No. 05-0315 (HELCO test year 2006), Docket No. 2006-0386 (HECO test year 2007), Docket No. 2006-0387 (MECO test year 2007) and Docket No. 2008-0083 (HECO test year 2009).
[28] DBEDT OB at 42.

by any earnings sharing credits or major capital projects credits to customers. See HECO OB at 28.

The components of the Company's revenue requirement that are subject to update and escalation through the RAM Provision include the revenue requirements associated with (1) changes in designated O&M expenses (referred to as "Base Expenses" in the RAM Provision), (2) the return on incremental investment in designated rate base components, (3) incremental depreciation and amortization expenses, and (4) changes in costs due to significant changes in tax laws or tax regulations (Exogenous Tax Changes in the RAM Provision). See HECO OB at 28-29.

O&M Expense Component of RAM

For the O&M expense component of the RAM, "Base Expenses" will be segregated between labor and non-labor amounts, with (1) the labor component quantified for the RAM Period by application of the Labor Cost Escalation Rate that is reduced by the Labor Productivity Offset, and (2) the Non-labor component quantified for the RAM Period by application of the Non-labor Escalation Rate. HECO OB at 29.

Base Expenses include the labor and non-labor operations and maintenance expense amounts approved by the Commission in the most recently completed rate case where the test year was the Evaluation Period,[29] or alternatively as authorized by the Commission in its Tariff Order for the immediately preceding year RAM Period if the Evaluation Period was not a test year.

Tracked O&M expenses for fuel, purchased power, pension/other post employment benefits ("OPEBs"), IRP/demand-side management or other rate adjustment provisions, will be

[29] The Evaluation Period is the historical twelve month period ending December 31, of each calendar year preceding the Annual Evaluation Date.

carried forward into the RAM Period at the fixed amounts established in the most recent rate case proceeding, because any changes in these costs is accounted for separately in other cost tracking mechanisms. HECO OB at 29.

The labor component will be quantified for the RAM Period by application of the Labor Cost Escalation Rate, reduced to account for the Productivity Offset to labor expenses.[30] The Labor Cost Escalation Rate will be the applicable annual percentage general wage rate increase provided for in currently effective union labor agreements between the Companies and the International Brotherhood of Electrical Workers, Local 1260, for use in escalating wage and salary Base Expenses for both union and non-union employees to determine revenue requirements for the RAM Period. In the event no union labor agreement exists for a RAM Period, the most recently effective annual percentage general wage rate increase will apply. See HECO OB at 29-30.

The Non-labor component will be quantified for the RAM Period by application of the Non-labor Escalation Rate. The Non-labor Cost Escalation Rate will be the consensus estimated annual change in the Gross Domestic Product Price Index ("GDPPI") to escalate non-labor Base Expenses to determine Authorized Base Revenues for the RAM Period. The GDPPI escalation rate will be the consensus projection published by the Blue Chip Economic Indicators (Aspen Publishing) issued in February of the year of the RAM filing. No productivity offset is applied to the non-labor escalation rate. The GDDPI is a measure of national output price inflation that already includes the impact of productivity and the application of a further productivity offset would double count the impact of productivity. See HECO OB at 30.

[30] The annual Productivity Offset is fixed at 0.76% and will be subtracted from the Labor Cost Escalation Rate applicable to Base Expenses to determine revenue requirements for the RAM Period. This 0.76% Productivity Offset rate was included in the Companies' Performance Based Ratemaking Proposal application, Docket 99-0396, filed December 13, 1999.

Rate Base Component of RAM

The Rate Base (for the RAM Period) will be the average net investment estimated for the RAM Period, including each of the elements of rate base reflected within the most recent rate case Decision and Order issued by the Commission, quantified in the manner prescribed in §2(f) of the RAM Provision. The Authorized Base Revenue associated with Rate Base will be determined by multiplying the applicable Return on Investment percentage rate times Rate Base. The Authorized Base Revenue associated with return on investment will include related income taxes on the equity components of such return. See HECO OB at 30-31.

In effect, the average rate base for the RAM Period (i.e., the Rate Base) will be the rate base for the rate case test year, with adjustments for changes in only four components of rate base, including (1) average plant-in-service, (2) depreciation reserve (i.e., "Accumulated Depreciation"), (3) accumulated contributions in aid of construction ("CIAC") and (4) accumulated deferred income taxes ("ADIT"). All other components of the rate base will remain the same as those in the preceding rate case test year rate base. See HECO OB at 31.

The average plant-in-service amount will be equal to the average of (1) the actual plant-in-service balance as of the end of the year prior to the RAM Period (termed the "Evaluation Year"), and (2) the same year-end balance plus estimated plant additions for the RAM Period. Estimated plant additions for the RAM Period will be set at Baseline Capital Project plant additions plus Major Capital Projects plant additions estimated to be in service by September 30th of the RAM Period (based on the "approved" cost estimates for such projects). See HECO OB at 31.

Baseline Capital Project plant additions will be calculated based on the simple average of Baseline Capital Projects plant additions recorded in the immediately preceding five calendar years. Major Capital Projects include capital investment projects that require application and Commission approval to commit funds pursuant to Decision and Order No. 21002 (Docket No. 03-0257) ("D&O 21002") "For Exemption From and Modification of General Order No. 7, Paragraph 2.3 (g), Relating to Capital Improvements." However, if specific Major Capital Projects are to be included in the Clean Energy Infrastructure Surcharge, they will not be included within the RAM provision so as to avoid any double recoveries. See HECO OB at 31-32.

The other elements of rate base that are adjusted include:[31]

(1) Accumulated Depreciation at December 31 of the RAM Period is quantified by increasing the recorded balances at December 31 of the Evaluation Period by the amount of the RAM Period depreciation and amortization expense amount;

(2) CIAC is quantified by adding to the recorded balance at December 31 of the Evaluation Period an estimate of the net change for the RAM Period. The net change will be based on a simple average of cash and in-kind CIAC for the immediately preceding five calendar years for programs plus specific engineering estimates of any contributions for the Major Capital Projects that are added to rate base during the RAM Period; and

(3) Accumulated Deferred Income Taxes is quantified by adding to the recorded balances at December 31 of the Evaluation Period the estimated tax effect of the depreciation timing difference (i.e., difference between book depreciation and tax depreciation) on the Baseline Capital Projects and Major Capital Projects added to rate base during the RAM Period.

[31] See HECO OB at 32.

Rate Base RAM Questions During the Hearings

Questions were raised during the proceeding with respect to (1) the use of estimates in the rate base RAM component, (2) the inclusion of actual plant costs in the beginning of year balances, and (3) and the rate base elements for which changes in revenue requirements should be reflected.

Use of Estimated Plant Additions

The use of estimates is a necessary part of a compensatory rate base RAM component. The Joint Decoupling Proposal, however, minimizes the reliance on estimates by using beginning of year actual balances, and conservative estimates of plant additions during the year. See HECO OB at 94.

The use of estimated plant additions in the rate base RAM component is consistent with cost-of-service ratemaking in Hawaii and other jurisdictions that use a future test year . Moreover, the estimates used in the Joint Decoupling Proposal are very conservative, and ratepayers have added protections under the proposal for major projects.

The use of estimated plant additions for a future test year also has been explicitly sanctioned by the Hawaii Supreme Court. The Court explicitly affirmed the Commission's finding that a utility's plant-in-service was "used and useful" for public utility purposes where the utility's 1976 rate base was based on its 1975 year-end balances and estimated plant additions for 1976 using the utility's capital budget estimates. See *In re Hawaiian Telephone Company*, 49 P.U.R. 4th 139, 65 Haw. 293, 651 P.2d 475 (1982). See also *Baltimore Gas & Electric Co. v. McQuaid*, 220 Md. 373, 152 A.2d 825 (Md. Ct. App. 1959).

As stated above, the estimates used in the rate base RAM proposal are inherently conservative. First, the base line plant additions estimate is based on a five year average, and not a trended estimate, as was originally proposed by the HECO Companies. Thus, the estimates do not incorporate the impact of inflation.

Second, only the General Order No. 7 ("G.O.7") projects that are expected to go into service in the first three quarters of the year are included in the major project estimate. Moreover, if major projects that do not actually go into service in the first three quarters were included, there is a refund condition to protect the interests of ratepayers.[32]

Third, the estimated costs that are used in the estimated major plant additions component are limited to the estimates approved in the G.O.7 proceedings.

In addition to the questions regarding the use of estimated plant additions, there were questions asked during the proceeding regarding the use of actual plant balances for the beginning of year balances in the rate base RAM, since there would be no review of the reasonableness of cost overruns in the case of G.O.7 projects, or project costs in the case of projects under the G.O.7 threshold.

In response to these questions, the HECO Companies and the Consumer Advocate pointed out that they intended to include a refund condition in the case of G.O.7 project cost overruns that were subsequently disallowed when reviewed in a rate case (as evidenced by the wording to that effect in Exhibit C to the Joint FSOP), and the wording in the proposed RAM tariff provision was revised to incorporate the Major Capital Projects Revenue Credits provision. See HECO OB at 46. In the case of Hawaiian Electric's EOTP project, it also was noted in

[32] The rate base RAM component of the Joint Decoupling Proposal includes major capital projects placed into service in the first nine months of the RAM year. As major projects might experience delays in completion due to a variety of reasons, the Major Capital Projects Credit mechanism would refund ratepayers with interest for major capital projects originally included in the rate base RAM calculation but were subsequently placed into service after the first nine months of the RAM year. This provides a safeguard for ratepayers in having to pay for capital projects which have not been placed into service in the first nine months as initially projected in the RAM year.

Major Capital Projects Revenue Credits are amounts that will be returned to customers as credits through the RBA for the preceding year's authorized base revenue amounts (including interest at the rate described in the RBA Provision) associated with specific major projects that were not placed into service within the first nine months of the preceding RAM period. HECO OB at 46.

Exhibit C that pre-2003 planning costs (and related AFUDC) would not be included in the rate base RAM beginning of year balance sue to the stipulation in the EOTP docket.

It should also be noted that instances of disallowed project costs are relatively rare in Hawaii, and have been limited to projects subject to unique circumstances (such as the extended delays experienced by the Keahole CT-4 and CT-5 generating units). There is an extensive reporting process required for G.O.7 capital projects in Hawaii, and detailed reasons for cost variances are provided.

Nonetheless, the HECO Companies stated in their Opening Brief that they are willing to expand the rate base RAM language to state that the Companies will refund (with interest) RAM revenues associated with disallowed costs for baseline projects (i.e., projects estimated to cost less than $2.5M). With the revision, if baseline project costs are disallowed to a point where the total amount of baseline projects' costs are below what was estimated and used to calculate the rate base RAM, the Companies will refund the RAM revenues associated with the difference, with interest. This change should address any concern that ratepayers might "pay" for projects that have not been reviewed and found to be "prudent". See HECO OB at 97-98.

The HECO Companies also willing to revise the rate base RAM component for major (i.e., G.O.7 projects) to include only the cost estimate for each project authorized in the G.O.7 proceeding, even in the beginning of the year balance, until a project's actual cost is reviewed in a rate case and included in revenue requirements in an interim or final rate order. See HECO OB at 98.

To address any concern with respect to whether projects have actually gone into service, the rate base RAM could be updated on a quarterly basis to recover costs for major projects that are placed into service in earlier quarters. See HECO OB at and Exhibit B. The revenue requirements for these projects would be based on 100% of the G.O.7 authorized costs for these projects, times the ratio of the months remaining in the year following the month in which the project goes into service to 12, which would be equivalent to using a weighted average rate base for these projects.[33] Currently, the joint proposal rate base RAM, which is only filed annually, includes one-half the cost of major project additions at G.O.7 authorized amounts, from the beginning of the year, if the projects are forecasted/scheduled to be placed into service in the first 9 months of the RAM year. In the revised proposal, the rate base RAM would include costs for the major projects only after they are placed into service. The filings to include the revised rate base RAM revenues in customers' rates would be made quarterly (with a one-quarter lag from the quarter the major projects are placed into service).[34] See HECO OB at 98.

Under the revision, the Rate Base RAM component would include actual costs for major projects, limited to the G.O.7 authorized amounts (unless a higher amount was allowed in a rate case or other proceeding). For those major projects with recorded costs less than the G.O.7 authorized amounts, the RAM will only include the recorded amount.[35]

To address concerns regarding the cost of CT-1, the Companies propose that the Hawaiian Electric RAM provision explicitly state that the RAM will only include CT-1 amounts

[33] Including 100% of the cost for one-half the year for a project that goes into service on July 1st is equivalent to including one-half of the project's cost for the entire year.

[34] The proposed quarterly filings will only account for major projects. Approximately seven to ten major projects a year are placed into service for Hawaiian Electric. Far fewer major projects are placed into service annually for MECO and HELCO. Thus, the tracking, reporting, calculation, filing, for the RAM and review by other parties of the quarterly filings should not require a substantial amount of extra effort. Since only major projects that are placed in service can be included in the rate base RAM, the nine months restriction in the current proposal would be eliminated. See HECO OB at 98-99.

[35] In the Joint Decoupling Proposal, major projects are reflected in the beginning of the year ("BOY") plant-in-service balance at their actual cost, which allows for the beginning balance for each RAM year to be based on the recorded books of the Companies. Customers are protected by a refund requirement if a lower cost is allowed to be included in rate base in the next rate case. To respond to concerns that refunds are not a complete remedy, the rate base RAM component would be revised in this alternative so that the BOY plant-in-service recorded balance be adjusted to reflect major projects at their actual cost, limited to their G.O.7 approved amounts. By lowering the BOY plant-in-service, the calculated rate base is also lowered,.and the rate base RAM is reduced, (including the depreciation expense associated with the lower PIS balance). See HECO OB at 99.

that are authorized by the Commission.

<u>Other RAM Components</u>

Depreciation and CIAC amortization expenses will be quantified for the RAM Period by application of Commission-approved accrual rates to the actual recorded Plant in Service (or other applicable) balances at the end of the Evaluation Period. <u>See</u> HECO OB at 32.

Exogenous Tax Changes include changes in tax laws or tax regulations that are estimated to impact Authorized Base Revenues by $2,000,000 or more for Hawaiian Electric, or $500,000 or more for HELCO or MECO. <u>See</u> HECO OB at 32-33.

<u>Comments of the Other Parties</u>

In its opening brief, DBEDT claims that the Commission should incorporate "consumer safeguards" into the decoupling design because "decoupling will undoubtedly result in rate increases." DBEDT OB at 17. The following are the "consumer safeguards" that DBEDT suggests that may be adopted:

a. Impose a cap on the amount of the total rate increase in between rate cases as was done by other states (i.e., Idaho, Oregon, Washington, Maryland, New York, and Wisconsin) that have implemented a decoupling mechanism.

b. Impose maximum bounds on the GDPPI or any cost indices as may be approved by the Commission to adjust any cost categories in determining the target revenue requirements adjustments in between rate cases.

c. Impose a percentage cap on the amount of "baseline capital projects" that HECO proposes to include in the ratebase adjustment component of the proposed RAM. DBEDT notes that HECO's proposed use of the <u>recorded</u> net plant-in-service at the beginning of the RAM year (i.e., Jan I, 2010 for 2010 RAM year) and the use of the historical average of the <u>recorded</u> "baseline capital projects" costs for the preceding immediate 5-year period (as proxy for the "base plant capital additions" for the RAM year) would reflect the cost overruns <u>twice</u> in the resulting calculated average rate base for the RAM year.

d. Exclude or limit the amount of specific major plant capital expenditures (e.g., projects that are contentious like CT-l) from the "major capital plant" costs that HECO proposes to include in the ratebase adjustment component of the proposed RAM.

e. Impose a percentage cap on the amount of "major capital plant" costs that may be included in the ratebase adjustment component of the proposed RAM.

DBEDT OB at 18-19.

DBEDT mischaracterizes the above as "consumer safeguards". The above proposals are just meant to reduce the RAM as calculated by the Companies' and Consumer Advocate's proposed RAM methodologies.

Items a and b above state that the Commission should cap the total amount of the annual RAM increases or cap the cost escalators used to determine the annual O&M expense RAM. These proposals should not be considered as viable options since they imply that the Commission should arbitrarily establish "caps". DBEDT offers no proposals on what the caps should be or how the Commission should determine what are appropriate levels for the caps.

In item c, DBEDT recommends a percentage cap on the amount of baseline capital projects. Again, this proposal should be rejected since DBEDT does not provide information on what the cap should be and how it is determined. Also, DBEDT's proposal is based on its misinterpretation of the Companies' and the Consumer Advocate's proposal for determining the rate base RAM. DBEDT states that the RAM "would reflect the cost overruns twice in the resulting calculated average rate base for the RAM year." First, "cost overruns" for baseline projects are not defined. Unlike the major projects that are reviewed and approved for a certain level of cost via G.O.7 proceedings, baseline projects include the total amounts of capital investment completed and closed to plant in service, excluding amounts related to major projects. Baseline projects have no Commission-approved level of costs to compare against recorded amounts to even determine that there are "cost overruns". In addition, the rate base

RAM methodology determines an average rate base for the RAM year by beginning with the beginning of year plant in service balance and adding a conservative amount of calculated net additions which would then produce an end-of-year plant in service balance. The beginning and calculated end-of-year plant in service balances are then added together, and divided by two, to determine the average rate base to be used for the RAM. This is identical to the methodology that is used in the rate case. So the beginning-of-year balance is different, separate, and not redundant with the net additions used in the calculation. Because the rate base RAM methodology calculates a baseline capital projects estimate based on the historical 5-year average of recorded baseline projects, it is a statistic and not related to any actual projects.

DBEDT recommends excluding or limiting specific major plant capital projects or imposing a percentage cap on the amount of major project costs that may be included in the rate base for determining the RAM. DBEDT does not state why the Commission should limit including the major projects' costs since these are projects that required application and Commission approval to commit funds pursuant D&O 21002 (G.O.7). Thus, the Commission has completed its review of the need for the projects and their cost budget. The proposed RAM methodology in the FSOP states that the major projects will be included in the rate base RAM at their actual costs, limited to their G.O.7 approved levels. So cost overruns are not included for the major projects in determining the rate base RAM.

In its opening brief, DBEDT also proposes to exclude all labor cost increases from the O&M expense component of the RAM. See DBEDT OB at 18-19 and 30-31. DBEDT argues that:

> [T]he HECO Companies' O&M labor expense should be maintained at the approved level in the utility's last rate case in the determination of the RAM revenue requirements adjustment. A guaranteed pass-through of labor cost increases at the current contractual wage rate increase as proposed in the

> HECO/CA Joint Proposal could very likely eliminate the utilities' incentive to prudently manage their labor costs through the contract negotiations with the union.

DBEDT OB at 30-31 (footnote omitted).

Labor costs in the O&M expense RAM are very conservatively estimated. First of all, labor costs currently comprise less than 40% of the total O&M expense (excluding fuel and purchased power expense) as reflected in Exhibit C, Attachment 6.[36] And, if fuel and purchased power expense were included, labor costs for O&M expenses in the 2009 test year would amount to less than 8% of total O&M expenses.

Moreover, the Companies do not "automatically pass through HECO's current contractual labor wage increase", as DBEDT claims. In their opening brief, the Companies explain that the labor component of the O&M expense RAM is escalated by a Labor Cost Escalation Rate, which is the applicable annual percentage general wage rate increase provided for in the currently effective union labor agreements between the Companies and the International Brotherhood of Electrical Workers, Local 1260, offset by the Annual Productivity Offset, which is fixed at 0.76%. See HECO OB at 29-30. As a result, the annual increase as reflected in the bargaining agreement is reduced by nearly 17%, and the RAM will reflect less than the annual percentage general wage rate increase as reflected in the bargaining unit agreement.

The labor cost increases estimated for the 2010 O&M expense RAM totaled $2,995,000.[37] This represented only a 3.74% increase from the O&M labor expenses in the 2009 test year of $80,119,000, as filed in the Companies' Statement of Probable Entitlement and not

[36] FSOP, Exhibit C, Attachment 6 at 1.

[37] $2,995,000 is the sum of the differences between the 2009 test year labor costs and the 2010 escalated labor costs for Production, Transmission, Distribution, Customer Accounts, Customer Service, and A&G. The revenue requirements for the O&M labor component for 2010 (after grossing up for revenue taxes) would be $$3,286,000, of the $5,365,000 total shown in Attachment 6 for the O&M expense RAM for 2010.

the 4.5% referenced by DBEDT.

In addition, the labor cost increase in the O&M expense RAM translates to a rate of approximately 0.04 cents per kWh for residents. A typical family of four that uses an average of 600 kWh per month would expect to see their monthly bill increase by only 26 cents to support the labor expense escalation as reflected in Exhibit 1, a modest increase in comparison to the monthly residential bill of $169.24 at proposed rates based a typical 600 kWh monthly usage (HECO T-22 Rate Case Update, Attachment 1, Page 16, Docket 2008-0083, filed December 26, 2008). The benefit to the Company's financial integrity of allowing some RAM recovery for labor cost increases would be significantly greater than the cost to ratepayers.

Most importantly, the O&M expense RAM calculation does not factor in "growth" in the number of employees hired between rate cases which may be substantial so the additional O&M labor expenses associated with the new hires are not passed on to ratepayers. For instance, at the end of 2006 and 2007, Hawaiian Electric had a total of 1,449 and 1,493 employees, respectively.[38] At the end of 2008, Hawaiian Electric had a total of 1,551.[39] This means that over the two-year period, the number of employees increased by 102 employees. If the RAM had been in place during 2007 and 2008, it would not have reflected any of the additional labor costs for these 102 new employees and Hawaiian Electric would have absorbed these additional labor expenses and not have passed them on to customers as part of the RAM.

4. **RBA Revenue Allocation**

The RBA tariff provisions included in the Joint Decoupling Proposal provide for the RBA balances (net of any credits) to be recovered through separate per kWh RBA rate adjustments, one for residential customers and one for commercial and industrial customers.

[38] Rate Case Update, Docket No. 2008-0083, HECO T-15, filed December 12, 2008 at 17.
[39] HECO-S-1511, Docket No. 2008-0083, filed July 20, 2009 at 3.

Separate RBA adjustments for residential customers and non-residential customers were proposed to give assurance that the decoupling adjustment will not subsidize one of the two groups at the expense of the other. Furthermore, the aggregation of all non-residential rate schedules into one customer class (instead of adjusting by individual rate schedules) will eliminate the possibility that a closure of a large customer (say in Schedule P) will result in having the RBA adjustment spread among just the customers remaining in its rate schedule. See HECO OB at 91-93.

As stated in the HECO Companies' Opening Brief, a single RBA rate adjustment, which would include the RAM revenue adjustment and would apply to all customer classes, also could be considered.[40] The advantages of a single RBA account and a single RBA rate adjustment include (1) simplicity of administration, (2) a smoothing of customer impacts between rate cases, and (3) an allocation of costs that is a proxy for a revised cost-of-service study. The tracking of and accounting for target revenues at the Company level would be easier to complete and document. The advantage of smoothing of customer impacts arises from spreading shortfalls or overages from target revenues to all customers rather than to a subset group of customers. If the difference of actual sales from test year sales and the costs associated with a RAM revenue adjustment were reflected in a revised cost-of-service study, all rate schedules would be assigned a cost adjustment. A single RBA rate adjustment in effect is a simplified proxy for completing a revised cost-of-service study between general rate cases. The HECO Companies' understanding is that this alternative is acceptable to the Consumer Advocate.

In its post-hearing questions, the Commission asked whether it is "lawful for the Commission to impose a decoupling charge on customer categories that have reduced their

[40] For MECO, a single consolidated RBA rate adjustment could apply to all customers at Maui, Lanai, and Molokai Divisions.

consumption, while granting a decoupling credit to customer categories that have increased their consumption, given the state policy of inducing a reduction in consumption?" The Commission also asked the parties to discuss the advantages and disadvantages of allocating the decoupling charge based on increases, rather than decreases, in a customer category's consumption.

As HDA notes in its Opening Brief: "Allocating higher costs to a customer class would not discourage consumption. Allocating a credit to a customer class would not induce consumption. This is because consumption decisions are made by individual customers, not by customer classes." HDA OB at 36.

The Consumer Advocate notes in its Opening Brief that, pursuant to HRS § 269-16(b), the Commission may allow reasonable discrimination between localities or consumers under similar conditions. "In the instant case, the overall State policy is preserved by this decoupling/RAM process and framework in that the broad encompassing intent of this process is to incentivize customer and utility participation in energy efficiency, demand response, and renewable energy while decreasing the impact and burden of frequent rate hikes that would be necessary to allow the utilities to recoup related lower revenue costs." CA OB at 16-17.

5. **Other Decoupling Mechanisms**

The HECO Companies examined all of the decoupling mechanisms employed in the energy industry, before settling on the "hybrid" RAM presented in their Preliminary Statement of Position ("PSOP") filed January 30, 2009. The discussion of the decoupling mechanisms was included in the PEG Report.[41] One of the primary considerations was the ability of the mechanism to replicate cost-of-service ratemaking, while being relatively simple to administer.[42]

[41] The final version of the PEG Report was filed February 3, 2009. The PEG Report is no longer deemed to be confidential, as indicated by the HECO Companies' transmittal on February 24, 2009.

[42] PEG was asked to (1) review and survey the various RAMs that have been and are in use by other utilities, particularly including those used by the California electric utilities, (2) simulate the financial

The Joint Decoupling Proposal developed by the HECO Companies and the Consumer Advocate also incorporated this consideration, but is more conservative from the standpoint of customers, is even simpler to administer, and contains additional customer protection features (including the earnings sharing mechanism).

The hybrid RAM[43] proposed by the HECO Companies and the Consumer Advocate is neither novel nor untested. A variety of approaches to RAM design have been used in California since the inception of decoupling, but the hybrid approach has been the most common over the years.[44] See PEG Report at 23-25 (Table 2 showing hybrid RAM mechanisms implemented in California).

The only party that proposed an alternative to the RAM was HDA, which presented a RPC mechanism. As described by HDA's representative in its closing statement, its intent was to offer a "vanilla" alternative to the RAM in the form of an RPC mechanism, which was not intended to address financial integrity issues such as regulatory lag. Thus, HDA did not take the position that the RPC mechanism should be adopted instead of the RAM. Tr. (7/1/09) at 723-25 (Freedman). HDA reiterated this in its Opening Brief, in which it stated that "the HDA RPC mechanism should be approved as a reasonable mechanism to serve in lieu of the RAM if the RAM is not approved or is suspended for any reason and the Commission decides to continue a

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impact of these alternative RAMs for HECO, HELCO, and MECO over a recent historical period of 1996 through 2007 to determine whether such RAM alternatives would provide the individual companies with sufficient financial resources, (3) determine the impact of different rate case cycle intervals on the individual companies' financial sufficiency, (4) recommend specific indices to be considered by the HECO Companies in their hybrid RAM proposal, and (5) simulate the financial impact of these specific indices to determine the financial sufficiency provided to the individual HECO Companies.

[43] The Joint decoupling Proposal is essentially a hybrid RAM, in which operations and maintenance ("O&M") expenses are escalated using a formula that includes inflation or input cost escalators (a formulaic approach), and rate base is escalated based on a trended forecast and actual balances. The term "hybrid" refers to the combination of formulaic and forecast approaches to derive the annual change in target revenue requirements.

[44] For example, the all forecast approach to RAM design was employed in some of the earliest RAMs. PEG Report at 25-27 (Table 2), 35. In addition, California utilities have employed the inflation only RAM approach, and the full indexing RAM approach. PEG Report at 27-28 (Table 2), 35. The RPC freeze approach, however, has not been implemented in California, as it does not address changes in an electric utility's revenue requirements between rate cases.

decoupling mechanism . . . ." HDA OB at 9.

The HECO Companies addressed the reasons why the RAM jointly proposed by the HECO Companies and the Consumer Advocate was definitely preferable to an RPC mechanism in the PEG Report, in their Comments on the NRRI Scoping Paper (which was filed February 20, 2009), in their Initial Statement of Position on HDA's Decoupling Proposal (filed March 30, 2009), and in responses to IRs. See also Exhibit A to this Reply Brief.

The RPC mechanism proposed by HDA does not attempt to address the objectives of the RAM to partially recover, between rate cases, the increases in costs that are fixed in the short term due to inflation, changes in utility output, and investments in utility infrastructure and, thus, to help maintain the financial health and integrity of the utility. See response to PUC-IR-46 at 1.

RPC mechanisms are commonly employed by natural gas local distribution utilities (LDCs), where a large portion of fixed costs are tied directly to, and vary with the number of customers. The HECO Companies' fixed costs are not related to the number of customers. Thus, as a means to help ensure that the Companies remain financially healthy between rate cases, the RPC methodology will not perform nearly as well as the RAM that is jointly proposed by the Companies and the Consumer Advocate. See response to PUC-IR-46 at 2-4.

To avoid financial attrition, utilities operating under RPC freezes file rate cases more frequently. This raises regulatory cost and can compromise utility cost performance. A RAM that provides relief for inflation as well as customer and activity growth makes it possible to simultaneously reduce regulatory cost and improve utility performance. That is why most RAMs that have been implemented in the U.S. and other countries over the years have not employed a RPC freeze. See response to PUC-IR-5 at 1; see also response to PUC-IR-46 at 3-4.

NRRI also requested that the Parties comment on the RPC mechanism, and several RAM variations, which alone or in combination might be considered alternatives to the RAM in the Joint Decoupling Proposal. The Commission issued Post-Hearing IRs on July 15, 2009. The third question (re-designated PUC-IR-52 for purposes of the responses) identified a number of possible RAM components, including (1) a revenue adjustment equal to the authorized return and depreciation on net additions related to system reliability (designated 3.a), (2) a revenue adjustment equal to the authorized return and depreciation on net additions related to customer additions (designated 3.b), (3) a revenue adjustment equal to difference in O&M costs associated with complying with Act 155 (designated 3.c), (4) the O&M portion of the RAM proposed by the HECO Companies (i.e., RAM without rate base adjustments) (designated 3.d), (5) the total of items 3.a, 3.b and 3.c, (6) the total of items 3.a, 3.b and 3.d, and (7) each of the above with and without RPC "reset". The HECO Companies presented their comments in their responses to PUC-IR-57 and PUC-IR-61. See Exhibit A to this Reply Brief.

These options, individually, would provide compensation for one or two cost drivers, but none of them, individually, would be sufficient to address increases in revenue requirements between rate cases or to avoid frequent rate cases. A combination of the options would, naturally, make an alternative RAM composed of them more compensatory. Options 3.a and 3.b together come close to providing the needed capital cost escalation for a majority of the Companies' annual plant additions, since most of the plant additions relate to reliability or customer additions. The complexity added by limiting the rate base component to specific categories of plant additions does not appear to be justified, as utilities are entitled to earn a return on all used or useful property used for utility purposes. In addition, an O&M component would still be needed. Option 3.c, by itself, would be clearly deficient as an escalator of O&M expenses.

6. **<u>Earnings Sharing Credit Mechanism</u>**

The Joint Decoupling Proposal includes an Earnings Sharing Revenue Credit Mechanism. Earnings, as measured by return on equity ("ROE"), achieved by each of the HECO Companies, are to be calculated for each calendar year that includes RAM revenues. Ratepayers would then be credited with the revenue equivalent of ROE levels actually achieved within the sharing matrix previously discussed. HECO OB at 45.

The proposed earnings sharing grid is intentionally asymmetrical, with no surcharges to ratepayers if achieved ROE is below the authorized ROE level. Earnings monitoring and sharing reports will be prepared by the HECO Companies and submitted on an annual basis. See HECO OB at 45.

The earnings sharing mechanism serves to: (1) provide a backdrop for the uncertainty associated with implementation of the Joint FSOP sales decoupling proposal; (2) prevent excessive cumulative cost recoveries (i.e., excessive revenues) under sales decoupling and the various new surcharge mechanisms envisioned by the Energy Agreement; (3) provide a periodic filing under RAM as an aid to regulatory understanding of whether RAM is reasonably balancing the interests of the utilities and ratepayers; and (4) explicitly reward utility performance with a sharing of any higher returns on investment if costs are successfully contained below RAM escalation rate expectations. HECO OB at 45.

The Companies are not aware of any issue regarding this provision. For example, HDA states that it "supports the ROE sharing mechanism proposed by the Consumer Advocate and now incorporated in the proposed RAM." HDA OB at 35.

7. **<u>Other Customer Protection Features</u>**

The HECO Companies and the Consumer Advocate are aware that decoupling mechanisms are new in Hawaii, although they have been implemented in other jurisdictions. Thus, the Energy Agreement includes a number of proposed review provisions that have been included in the Joint FSOP Decoupling Proposal, which provide the Commission, the Consumer Advocate, and the HECO Companies the ability to review the performance of revenue decoupling and take steps to correct, suspend, or terminate the mechanism. Further, the Consumer Advocate has proposed, and the HECO Companies accepted as part of the Joint Decoupling Proposal, a number of additional safeguards for ratepayers. For example, (1) the provisions would extend to each of the HECO Companies' next round of rate cases, at which time, upon Commission review and evaluation, the provisions may be extended, terminated or modified based upon evidence presented in those rate case proceedings, (2) an Earnings Sharing Revenue Credit mechanism to protect ratepayers against excessive utility earnings as a result of decoupling, (3) Major Capital Projects Credit mechanism to refund recovery of major capital projects placed into service after the first nine months of the year, and (4) a HCEI status report which tracks the Companies' performance against specific HCEI initiatives.

8. Timing of Decoupling

The Joint Decoupling Proposal contemplated that sales decoupling would be implemented for Hawaiian Electric, on an interim basis, with the interim rates implemented in Hawaiian Electric's 2009 test year rate case. The parties in that rate case stipulated to such an interim sales decoupling provision, but the Commission's Interim Decision and Order issued July 3, 2009 in Docket No. 2008-0083 did not authorize such a provision. The RAM (and the permanent sales decoupling mechanism) would be implemented as a result of the decision and order in this docket, and would be applicable to 2010.

The Joint Decoupling Proposal contemplates that sales decoupling and the RAM for

MECO and HELCO would be approved in the decision and order in this proceeding. Sales decoupling for the two utilities would begin when interim rates are made effective in their 2010 test year rate cases, and the RAM for each would be effective beginning in 2011.

HDA has proposed that the Commission issue an interim order in this docket to allow sales decoupling to be implemented immediately for Hawaiian Electric, and to ensure that the Hawaiian Electric RAM, if approved, is in place in 2010 on a one-year "pilot" basis. See HDA OB at 7.

Hawaiian Electric supports the proposal for an interim order in this docket, but opposes any shortening of the period in which the RAM and sales decoupling are initially in effect. The Joint Decoupling Proposal already provides that sales decoupling and the RAM will be re-examined in Hawaiian Electric's 2011 test year rate case.

The timing of decoupling, and the impact of decoupling on the rate case cycle, as proposed in the Joint Decoupling Proposal, are addressed in Section I.B of this Reply Brief.

9. Ongoing Review of Decoupling

A number of review provisions are included in the Energy Agreement, which provide the Commission, the Consumer Advocate, and the Companies the ability to review the performance of revenue decoupling and take steps to correct, suspend, or terminate the mechanism. They include the following:

(1) The parties agree that the decoupling mechanism that will be implemented will be subject to review and approval by the Commission.

(2) The Commission may review the decoupling mechanism at any time if it determines that the mechanism is not operating in the interests of the ratepayers.

(3) The utility or the Consumer Advocate may also file a request to review the impact of the decoupling mechanism.

(4) The Commission may unilaterally discontinue the decoupling mechanism if it

finds that the public interest requires such action.

The Consumer Advocate and the Companies propose that the review of the continuation of the RBA and RAM provisions be undertaken in the Companies second round of rate cases, to occur in 2011 through 2013.

The Joint Decoupling Proposal contemplates a three-year sales decoupling cycle (if decoupling is continued after the initial period), i.e., where rate cases are filed for test years that are three years apart. However, because the three HECO Companies will all have the same starting test year for the rate case cycles and are supported by the same regulatory department and the same witnesses for certain testimonies, in order to minimize the need for resources and be able to submit rate case filings of the highest quality possible in the future, the rate cases after the 2009 or 2010 test year would be staggered, so that three-year rate case cycles could commence thereafter. This will result in the filing of only one rate case per year after the initial round of 2009 or 2010 test year rate cases. Hence, the scheduling of the next round of rate cases would be as follows:

Company	Year of Filing	Test Year
Hawaiian Electric	2010	2011
MECO/HELCO	2011	2012
MECO/HELCO	2012	2013

The ability of Hawaiian Electric to refrain from filing a 2010 test year rate proceeding and wait until 2011 for its next rate case will depend on the outcome of this Decoupling docket, as discussed in Section I.B, above. Should Hawaiian Electric determine that a 2010 rate case filing is necessary, the HECO Companies will revisit the timing and starting point for the proposed three-year general rate case cycle.

C. ECAC FIXED HEAT RATE ISSUE

1. Position of the HECO Companies and the Consumer Advocate

The HECO Companies and the Consumer Advocate proposed the ECAC deadband concept as a means to balance the sometimes competing objectives of promoting efficient operation and the need to integrate additional renewable energy. As stated in the HECO Companies' and the Consumer Advocate's Joint Statement of Position, submitted on May 11, 2009, in Exhibit D, pages 2 and 3:

> In the April 20, 2009 Technical Meeting, the HECO Companies identified the reasons for keeping the fixed heat rate. First, the fixed heat rate provides an effective incentive for the utilities to maintain their generating units in order to run as efficiently as possible. Second, the fixed heat rate serves as a risk sharing mechanism, such that the utilities are at risk of not recovering all of their fuel expenses if they do not properly manage the generating units' operating parameters under their control.
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> Nevertheless, the HECO Companies agree with HDA that the fixed heat rate could result in the utilities recovering more or less than their fixed costs under sales decoupling, and that the fixed heat rate may incent the utilities to take less renewable energy under certain circumstances. The system heat rate worsens because utility generators must often be taken off of economic dispatch to accommodate increased levels of renewable energy.
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> Therefore, at the April 20, 2009 Technical Meeting, the HECO Companies stated that, in addition to considering HDA's proposal, they would consider a deadband around the fixed sales heat rates in the ECAC that preserves an effective incentive to operate efficiently, but also reduces the disincentive to accommodate increased amounts of renewable energy.

On June 25, 2009, the HECO Companies filed a modification and several illustrations, clarifications, a correction, and updates to the Joint Decoupling Proposal, as the Companies committed to do at the Prehearing Conference on June 22, 2009. The modification was included in new Attachment 7 to Exhibit C of the Joint Decoupling Proposal, which updated the HECO Companies and the Consumer Advocate's ECAC heat rate deadband proposal in Exhibit D of the Joint Decoupling Proposal to include the deadbands proposed for HELCO and MECO. See

HECO OB at 54. The complete heat rate deadband proposal is provided in Attachment 7 to Exhibit C but is partially summarized on pages 74-76 of the HECO Companies' Opening Brief.

2. Position of Blue Planet and HSEA[45]

Blue Planet responded to this issue by putting forth its view of the advantages and disadvantages of a straight fuel cost pass-through and of a "performance band" that was suggested in PUC-IR-62.[46] Blue Planet does not expressly endorse any particular type of ECAC mechanism (e.g., straight fuel cost pass-through, ECAC deadband, or ECAC performance band). However, Blue Planet's Opening Brief appears to favor a straight fuel cost pass-through, stating the advantages of such a mechanism and the disadvantages of the existing ECAC mechanism and the performance band concept. For example Blue Planet contends that:

(1) "[A] straight fuel cost pass-through may decouple utility earnings from operation reserve capacity decisions. The existing ECAC provides an incentive for utilities to minimize operation reserve capacity. Adding intermittent renewable generation resources to utility systems, however, may require increased operating reserve capacity. As with resource commitment and curtailment decisions, ECAC with full pass-through may reduce the HECO Companies' financial risk with providing sufficient operation reserves to accommodate intermittent renewable generation, thereby further supporting the rapid adoption of renewable energy."[47]

(2) "Eliminating the fixed heat rate efficiency component of the ECAC mechanism may remove a disincentive for the HECO Companies to integrate additional renewable energy resources into the grid."[48]

(3) "Adoption of the suggested heat rate performance band within which the HECO Companies would be financially at risk for changes in power plant heat rate may not, however, remove the renewable energy resource integration disincentive."[49]

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[45] HSEA filed a joinder with respect to Blue Planet's Opening Brief.

[46] As suggested by PUC-IR-62, a "performance band" would be "an ECAC in which (a) the utility bears the risk for heat rate changes within a performance band (e.g., plus/minus 50 Btu from the target) while (b) all changes in costs associated with heat rate changes outside the performance band are passed through to customers."

[47] Blue Planet OB at 16.

[48] Blue Planet OB at 16.

[49] Blue Planet OB at 16.

(4) "The current ECAC mechanism may also allow the HECO Companies to retain a portion of the fuels cost savings from a decline in sales. Thus, absent a straight cost pass-through ECAC, the HECO Companies may be overcompensated if a decoupling mechanism is implemented with the current ECAC and utility sales decline."[50]

If Blue Planet does in fact support a full pass-through of fuel expenses, Blue Planet's position (and accordingly HSEA's position) is the same as the positions of DBEDT, HDA and HREA, who, as discussed below, also support full pass-through of fuel expenses through the ECAC. As noted above, the ECAC deadband concept was proposed as a means to balance the objectives of promoting efficient operation and the need to integrate additional renewable energy.

3. Position of DBEDT

DBEDT does not support the adoption of a deadband around the fixed efficiency factor, and noted in its Opening Brief that, "Several parties in the instant docket, including DBEDT, advocated making the ECAC a full cost recovery mechanism and eliminating the efficiency incentive embedded in the ECAC calculation, if a decoupling mechanism is adopted by the Commission." DBEDT OB at 43.

DBEDT added:

> DBEDT's response to the PUC-Post-Hearing-IR-13 also provided the pros and cons of adopting a 'dead band' around the fixed efficiency factor as proposed by the CA and the HECO Companies in their JSOP filed on May 11, 2009. Essentially, DBEDT does not believe that adopting such proposed dead band around the fixed efficiency factor will address the concerns raised regarding the embedded incentive in the ECAC.[51]

PUC-Post-Hearing-IR-13 (referenced in DBEDT's OB, and relabeled as PUC-IR-62) contained the following request for information:

> Please discuss the pros and cons of an ECAC in which (a) the utility bears the risk

[50] Blue Planet OB at 16-17.
[51] DBEDT OB at 44.

> for heat rate changes within a performance band (e.g., plus/minus 50 Btu from the target) while (b) all changes in costs associated with heat rate changes outside the performance band are passed through to customers.

It appears that DBEDT misinterpreted the information request in PUC-Post-Hearing-IR-13. The IR refers to a "performance band" in which the utility bears the risk for heat rate changes (as it does under the existing ECAC mechanism), rather than a "dead band around a fixed efficiency factor" that DBEDT discussed, and where the deadbands actually occur outside of the plus/minus 50 Btu thresholds. In other words, the Commission was seeking information on an "inside-out" version of the deadband concept proposed by the HECO Companies and the Consumer Advocate.

Notwithstanding DBEDT's apparent misinterpretation, DBEDT does not appear to support adoption of the proposed dead band around the fixed efficiency factor. Rather, DBEDT advocates "making the ECAC a full cost recovery mechanism" (DBEDT OB at 43), but qualifies its position by stating that, "If the Commission does not wish to eliminate the fixed heat rate to allow a full pass-through of energy costs through the ECAC, DBEDT recommends instead to modify the determination of the fixed heat rate used in the ECAC . . . ." DBEDT OB at 44.

<u>Fixed Efficiency Factor as a Disincentive for Integrating Variable Renewable Generation</u>

According to DBEDT:

> [T]he built-in incentives in the ECAC calculation provide <u>disincentive</u> for the utilities to integrate and add renewable power generation, especially variable or intermittent renewable generation, in the system, as such addition would require the utility to run higher amounts of spinning reserve (or regulating reserve) which is more costly since these units must operate at lower output levels where efficiency is lower. Therefore, the fixed heat rate in the ECAC calculation could incentivize the utilities to run their units more efficiently and reduce variable renewable generation in the system (i.e., less renewable energy purchases or increased curtailment of purchased renewable power), thereby perpetuating the utilities' dependence on imported fossil fuels, which is not in Hawaii's best interest.

DBEDT OB at 31-32 (footnote omitted).

DBEDT's assertion is without merit, as Hawaiian Electric does not have the discretion to reduce variable generation in favor of its own fossil-fueled generation. Hawaiian Electric can lawfully curtail variable renewable generation only under very limited circumstances, such as when variable generation resources are violating performance standards, when there is excess energy on the system, or when accepting the energy would result in system problems. As Mr. Sakuda stated in the panel hearing:

> If the developer – if the project is already on the system and, let's say, it's an as-available project, a wind or photovoltaic, we don't have the same discretion. We have an obligation to take that energy, to the extent that the system can take it. There are only limited circumstances under which we cannot accept the energy, and those would be if the producer is violating performance standards. Two is if there's excess energy. In other words, we cannot keep supply and demand in balance. Or if there's a system problem, for example, a transmission line is out and accepting the energy would cause overloads on the system on alternative lines. There are limited circumstances in which we cannot accept the energy.

Tr. (7/1/09) at 573 (Sakuda).

Modification of Fixed Efficiency Factors, if Retained

If fixed efficiency factors continue to be used in an ECAC calculation, DBEDT asserts that they "must be modified such that these factors are calculated using the kilowatt-hours at the net generation level (resulting in lower heat rate value which means higher efficiency) rather than using the kilowatt-hours at the sales level (resulting in higher heat rate value which means lower efficiency)." DBEDT OB at 33.

According to DBEDT:

> The "sales level" heat rate reflects lower efficiency (i.e., higher heat rate value means lower efficiency) than the heat rate at the "net generation level" (lower value which is better efficiency), because the total fuel (in MBtu) which is based on the actual recorded efficiency (MBtu/bbl) of the utilities' generation units is divided by the lower sales level kilowatt-hours. Setting the fixed efficiency factor at the higher sales level heat rate value (11,140 Btu/kWh) instead of the lower heat rate value at the net generation level (10,602

Btu/kWh) which reflects the actual recorded heat rate, means that the resulting difference in the amount of fuel actually used at the higher efficiency (10,160 Btu/kWh) and the amount of fuel cost allowed to be recovered at the lower efficiency (11,140 Btu/kWh) represents the amount of fuel cost savings that the utility is allowed to keep.

DBEDT OB at 33-34.

DBEDT appears to misunderstand the calculation of heat rate. By way of background, in generating and delivering electrical energy to customers, the energy is first produced by the generators and delivered to transformers at power plants. The point at which the energy exits the transformers and enters the power grid is referred to as the "net-to-system" point. From there, the energy travels through the electrical transmission and distribution system to the customer. Along the way to the customer, energy losses occur and additional energy is consumed for utility use (sometimes referred to as "No Charge Energy"). As a result, the amount of energy arriving at the customer's meter (i.e., at the "customer level" or "sales level") is less than the amount of energy delivered at the net-to-system point.

The heat rate of a system can be calculated at the sales level or at the net-to-system level. For example, if 100×10^6 Btus (100 million Btu or 100 MBtu) of fuel at the power plant are required to serve 10,000 kWh of sales at the customer level, then the sales heat rate would be (100×10^6 Btus) / 10,000 kWh = 10,000 Btu/kWh-sales. Assuming further that in transporting the energy from the power plant to customers, there are 480 kWh worth of energy losses and an additional 20 kWh are consumed for Company use, 10,500 kWh of energy would be delivered by the power plant to the net-to-system level. (10,500 kWh of energy delivered at the net-to-system minus 480 kWh energy losses and 20 kWh consumed for Company use = 10,000 kWh remaining for sales.) Therefore, the net heat rate would be (100×10^6 Btus) / 10,500 kWh = 9,524 Btu/kWh-net.[52]

[52] See HECO's response to PUC-IR-109, filed in Docket No. 2008-0083 (HECO's 2009 test year rate

While the amount of energy (kWh) delivered at the net-to-system level versus the customer level may differ, the amount of fuel consumed at the power plant remains the same. Accordingly, the fuel efficiency or heat rate can be expressed as the amount of fuel used as a function of the amount of energy delivered at the net-to-system level or as a function of the amount of energy delivered at the customer level. Thus, it is important when stating fuel efficiency to indicate whether the units are in Btu/kWh-sales or Btu/kWh-net.

An analogy would be the expression of temperature, which can be measured in degrees Fahrenheit (°F) or degrees Celsius or Centigrade (°C). Water freezes at 0°C or 32°F. While the numerical values are different, they are a measure of exactly the same state. Only the units of measure are different. Similarly, 11,140 Btu/kWh-sales is equivalent to 10,602 Btu/kWh-net. They are measures of the same fuel efficiency; only the units of measure are different.

Where different units of measure are available to measure the same parameter (such as fuel efficiency or temperature), it is imperative to use the same units of measure in all calculations using that parameter.

To illustrate the point, consider the example given above where it takes 100×10^6 Btus (100 million Btu or 100 MBtu) of fuel at the power plant to serve 10,000 kWh of sales at the customer level, and there are 480 kWh worth of energy losses and an additional 20 kWh are consumed for Company use. The <u>sales</u> heat rate would be 10,000 Btu/kWh-sales and the <u>net</u> heat rate would be 9,524 Btu/kWh-net. Both measures of efficiency are equivalent because both represent the burning of 100 MBtu of fuel. However, the points at which the kWh are measured differ. In the former, the kWh are measured at the power plant; in the latter, the kWh are measured at the customers' meters.

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case).

For the purposes of expressing fuel efficiency in the ECAC, the use of the sales heat rate, in which kWh are measured at customers' meters, is the appropriate measure. This is because the ECA factors are applied to the amount of electricity sales measured at the customers' meters. Therefore, the fixed efficiency factor (heat rate) used in the ECAC to convert the price of fuel (in cents per Mbtu) to the ECA factor (in cents per kWh-sales) must be the sales heat rate:

Fuel Price x sales heat rate = ECA factor

$$\frac{\text{Cents}}{\text{Mbtu}} \times \frac{\text{Mbtu}}{\text{kWh-sales}} = \frac{\text{Cents}}{\text{kWh-sales}}$$

In determining fuel consumption in a rate case, the HECO Companies account for the energy delivered from the net-to-system level all the way to customer consumption. See, e.g., the attached exhibits HECO-402, page 1, filed in Docket No. 2008-0083 (Hawaiian Electric 2009 test year rate case); MECO-403, page 1, filed in Docket No. 2006-0387 (MECO 2007 test year rate case); and HELCO-403, page 1, filed in Docket No. 05-0315 (HELCO 2006 test year rate case). For example, in HECO-402, line 1 (sales) accounts for the energy delivered to the customer; line 2 is for Company Use; line 4 accounts for losses on the transmission and distribution system; and line 5 is the total net-to-system input. There is only a single value of fuel input at the power plant that produces the energy at the net-to-system level or at the sales level. However, two different heat rates can be calculated – one at the net-to-system level and one at the sales level – but they are measuring the same thing.

Effective Date of Revised Efficiency Factors

In its Opening Brief, "DBEDT recommends that if the Commission adopts a decoupling mechanism, the fixed efficiency factors should be revised and updated effective the same date as the decoupling mechanism, rather than waiting for the utilities' rate cases." DBEDT OB at 32-33. The revision DBEDT is referring to is the change in the basis of the fixed efficiency factor from the sales level to the net-to-system level. However, no such change is necessary, for the reasons cited above. Therefore, the issue regarding the timing of a revision is moot.

4. Position of HDA and HREA[53]

HDA's position with respect to this issue is that "the ECAC should be amended, either by adopting the deadband proposal recommended by Hawaiian Electric and the Consumer Advocate or by simplifying the ECAC to a straight pass through of actual fuel and purchased energy expenses." HDA OB at 9. "HDA favors changing the ECAC reconciliation to a full pass through of actual generation expenses along with regular reporting requirements and periodic review to ensure that efficient operation of the utility systems is maintained." HDA OB at 30 (footnote omitted). According to HDA, a full pass-through would be favorable because:

(1) "The deadband approach appears to be too simplistic to function properly. . . . A performance deadband approach is too simplistic to effectively differentiate between multiple performance factors using a single index that in some cases is to be minimized, in some cases maximized and in some cases ignored";[54] and

(2) "A deadband approach adds further complexity to an already complicated adjustment and reconciliation mechanism. This is not preclusive but is a substantial consideration, especially when compared to a simple straight pass through approach which would be a substantial simplification of the entire monthly, quarterly and annual ECAC process and the RBA decoupling process."[55]

The Companies' position is that the deadband proposal adequately addresses the concerns raised by HDA, without sacrificing the benefit of having the fixed heat rate target efficiency factor.

5. NRRI Alternatives

In its post-hearing IRs, NRRI asked the parties to comment on two alternatives to the

[53] HREA filed a joinder with respect to HDA's Opening Brief.
[54] HDA OB at 33-34.
[55] HDA OB at 34.

deadband proposal, including options in which (1) the utility bears the risk for heat rate changes within a performance band (e.g., plus/minus 50 Btu from the target), while all changes in costs associated with heat rate changes outside the performance band are passed through to customers (PUC-IR-62), and (2) the ECAC remains the same as the current ECAC, but the Btus used for spinning reserve are "removed" from the heat rate calculation (PUC-IR-63).

The first option does not adequately address the concerns raised by the other parties, and would be inferior to the deadband proposal, as well as the option of eliminating the fixed heat rate altogether. See HECO response to PUC-IR-62; see also HDA and CA responses to PUC-IR-62. Changes to the existing fixed heat rate within the current ECAC were prompted by concerns by the other parties that the fixed heat rate could result in the utilities recovering more or less than their fixed costs under sales decoupling and that the fixed heat rate may incent the utilities to take less renewable energy under certain circumstances. However, under the first option above, which Hawaiian Electric referred to as the "performance band concept" in its response to PUC-IR-62, the ECAC revenue plus base fuel energy charge revenue would never be representative of variable fuel and purchased energy expense, and the concept would only partially remove the disincentive for renewable energy additions that increase the heat rate.

If the actual heat rate was within the performance band, Hawaiian Electric would be unable to pass the changes in costs through the ECAC. Therefore, the ECAC revenue plus base fuel energy charge revenue would not be representative of variable fuel and purchased energy expense. Only when the actual heat rate is outside the performance band, would Hawaiian Electric be able to pass on the additional expenses through the ECAC, but only to the extent that the actual heat rate is above the upper performance band (which is 50 btu/kwh above the heat rate target, or is below the lower performance band (which is 50 btu/kwh below the heat rate target. Thus, even when the actual heat rate was outside the performance band, ECAC revenue plus base fuel energy charge revenue would not be representative of variable fuel and purchased energy expense and the utilities would continue to recover more or less than their fixed costs under sales decoupling.

The HECO Companies and Consumer Advocate jointly proposed a deadband around the fixed heat rate within which there would be a complete pass-through of fuel and purchased energy expenses. Thus, under the joint deadband proposal the utilities would more accurately recover their fixed costs under sales decoupling (when the actual heat rate is within the range of the upper and lower heat rate deadband). In contrast, with sales decoupling and the performance band concept, the utilities would continue to recover more or less than their fixed costs.

Furthermore, under the performance band concept, Hawaiian Electric, for example, would be able to recover the additional fuel expenses associated with additional renewable energy only to the extent that the heat rate resulting from the additional renewable energy increased the heat rate by more than 50 Btus above the fixed heat rate. It would still not be able to recover the additional fuel expenses related to a resulting heat rate that is between zero and 50 Btu/kwh higher than the fixed heat rate. Under the joint HECO Companies and Consumer Advocate deadband proposal, the additional fuel expenses related to a resulting heat rate that is between zero and 50 Btu/kwh higher than the fixed heat rate would be recovered. Moreover, the deadband proposal contains provisions to reset the target heat rate if triggers related to the amounts of renewable energy and the impact on heat rate are attained.

HDA suggests that "[a] performance deadband approach (regardless of whether it is structured "outside in" or "inside out") is too simplistic to effectively differentiate between multiple performance factors using a single index . . . One con regarding either performance deadband approach is some necessary added regulatory complexity."

The Consumer Advocate maintains that "[a] 'pro' for such an ECAC is the potential that if HECO were to perform better than the heat rate performance band, the benefits of doing so would be passed through to ratepayers." However "the above ECAC would not provide for a fair sharing of the risk of performance between HECO and ratepayers, would not provide a reasonable incentive for HECO to manage and operate its generating units efficiently, and would increase the burden and effort needed to audit and verify HECO's performance under the ECAC." Instead, "the Consumer Advocate believes that the heat rate band and the target heat rates established under the jointly proposed ECAC will provide an appropriate sharing of risk between Hawaiian Electric and the ratepayers, provide an incentive for Hawaiian Electric to reasonably manage and operate its resources reliably and efficiently, and provide for the greater use of renewable energy and sales reductions due to energy efficiency programs while preserving Hawaiian Electric's financial integrity.

The second option (where the ECAC remains the same as the current ECAC, but the Btus used for spinning reserve are "removed" from the heat rate calculation), is simply unworkable. See HECO response to PUC-IR-53 and PUC-IR-63; see also HDA, CA and Blue Planet responses to PUC-IR-63. All Btus generate electricity. Therefore, technically, it is impossible to "remove the Btus used for spinning reserve from the heat rate calculation."

In addition, spinning reserve is not "generated." Spinning reserve is the amount of reserve capacity that is immediately available from units that are connected to the system and are operating below their maximum rated levels. Thus, spinning reserve is the difference between the total amount of generating capacity connected to the system and operating and the total demand on the system.[56]

Moreover, regulating reserve is a subset of spinning reserve that responds to signals from automatic generator controls. In order to operate an electrical grid safely and reliably, supply (generation) and system demand must be kept in balance at all times (in addition to other considerations). Because demand on the system is constantly changing, some amount of regulating reserve is needed to maintain this balance.[57] It would not be possible to operate the grid safely and reliably without some amount of spinning or regulating reserve.

The Companies' systems cannot operate with zero spinning or regulating reserve. Because demand on the system is constantly changing, a reserve is needed to keep supply and demand in balance at all times. Without this reserve, the system would be subject to low frequency on the system and a possible interruption of service to customers. Moreover, there is always an inherent amount of reserve on the system because generation, when brought on line, comes on in large increments.

In order to operate with a given minimum level of spinning reserve or regulating reserve, units have to be "committed" (i.e., started up and synchronized to the grid) such that the total amount of generating capacity connected to the system and operating, minus the estimated total demand on the system, will equal or exceed the desired minimum amount of spinning reserve or regulating reserve. More Btus are required to generate the same amount of electricity as the minimum amount of spinning reserve or regulating reserve is increased.

Theoretically, the difference in Btus between a system with a spinning reserve or

[56] For example, if the total system demand is 100 MW and three 50 MW units are operating to serve this demand, the total amount of generation in operation is 150 MW. Only 100 MW of the three units' aggregate capacity are being used to serve the demand, and there are 50 MW of spinning reserve.
[57] For example, if the demand on a system is 1,000 MW and exactly 1,000 MW of generation is serving the demand, then if demand suddenly increases by 10 MW, such as when a large industrial customer begins operations, there would not be enough generation immediately available to serve the increased demand. This would result in low frequency on the system and a possible interruption of service to customers since some circuits that serve customers may trip out of service on underfrequency.

regulating reserve policy, and the hypothetical minimum spinning or operating reserve that could be carried to meet load requirements could be calculated. However, it would not make sense to remove the amount of fuel (Btus) used for spinning reserve (even if it could be done) from the heat rate calculation for the purposes of determining the amount of fuel cost that would be recovered through the ECAC. The provision of spinning reserve as well as regulating reserve is an essential part of providing reliable service. Moreover, such a calculation would not serve a useful purpose. One of the disadvantages to the hypothetical calculation of the fixed heat rate is that the ECAC and heat rate calculation would not reflect how the utilities operate the system and incur variable fuel expenses to ensure reliable service. Operating with spinning or regulating reserve improves service reliability, but increases heat rate because more units need to be operating and each unit must operate at a lower output level where its fuel efficiency is lower. See HECO responses to PUC-IR-53 and PUC-IR-63.

The responses of HDA, the Consumer Advocate and Blue Planet to PUC-IR-63 are consistent with the Companies' response. HDA responded as follows:

> HDA concurs with HECO's assertion in its response to PUC-IR-53 that it is not practical to isolate the Btu's attributable to providing spinning or regulating reserve from total fuel consumption. If it were practical to clearly differentiate the multiple components of fuel consumption and system operation efficiency, there would be merit in separating these components for the purposes of providing specific incentives. Unfortunately, this is not practical.

The Consumer Advocate responded as follows:

> Generally, there is not any fuel use, or Btu use, associated with spinning reserves, because spinning reserves are commonly referred to as the unloaded portion of generation that is on-line and "spinning." While some mainland utilities have developed a quantification of spinning reserve fuel use to add to the cost of transmission ancillary services, the amount quantified has generally been negligible. Therefore, removing the Btus associated with the spinning reserves, if quantifiable for HECO, is not likely to have any significant impact and any comparison between keeping the ECAC the same and with the modification proposed in the question would likely yield negligible pros and cons when only

considering the impact on the ECAC.

Blue Planet responded as follows:

> As a practical matter, it is not possible to measure the quantity of Btus used for spinning reserves. The reason is that no Btus are consumed to provide spinning reserves. Spinning reserves are provided by generating units already on-line which are producing electricity at less than their full rated capacity, and therefore represent on-line, real-time standby capacity. By definition, there is no spinning reserve electricity being generated that would require Btus of fuel consumption.

D. OTHER ISSUES AND REPLY COMMENTS

1. Service Quality Metric

Through IRs and during the panel hearings, questions were raised as to whether, under decoupling, the Companies have an adequate incentive to maintain their facilities or make repairs in a timely fashion during outages.

In their responses to PUC-IR-2 and PUC-IR-37, the Companies pointed out that service quality provisions are not commonly found in revenue decoupling plans. A utility's service quality is most likely to be jeopardized when real profits are to be made by cutting line maintenance expenses and other costs of maintaining or improving quality. Experience has shown that these profit opportunities depend chiefly on the length of time between rate cases. The great majority of decoupling plans do <u>not</u> involve rate case moratoria lasting four years or longer. Many decoupling plans in fact involve no rate case moratorium. Four years is normally considered the threshold term that would qualify an alternative regulation plan to be classified as an example of performance-based regulation ("PBR"), with cost containment incentives sufficiently strong to warrant quality concerns. Where quality provisions are included in PBR plans, they oftentimes involve only the monitoring of quality and not a program of awards and/or penalties, especially in first generation plans.[58] See HECO OB at 83-85.

In their recent white paper on decoupling for the Minnesota Public Utilities Commission,[59] the authors stated (on page 29) that:

> We doubt that decoupling, by itself, would lead to an erosion of customer service (and, indeed, we've seen no evidence of it in other jurisdictions). Public opinion, general regulatory oversight, and the utility's corporate culture are probably sufficient to prevent it.

Nonetheless, the authors proposed that service quality measures be included.

The Joint Decoupling Proposal includes an earnings sharing mechanism ("ESM"), in order to assuage concerns that the RAM will create windfall gains through improvident design. An ESM would, by sharing any surplus earnings with customers, further weaken incentives to take extreme cost containment measures that could jeopardize quality.

In addition, any service quality standards would have to be tailored to the circumstances of the utilities affected by the standards, in order to avoid unfair or unintended consequences. For example, MECO and HELCO do not operate with sufficient spinning reserve to cover for the loss of the largest unit. Adding more spinning reserve would impose additional costs on their customers. Instead the utilities rely on underfrequency load shedding schemes to balance load and generation, and small, quick start diesel units to restore service to customers affected by the load shedding events. Before imposing the same SAIDI standard on MECO and HELCO as those that may be applicable to Hawaiian Electric, the Commission would have to decide that customers should bear the additional cost of carrying more spinning reserve.[60]

[58] Following the hearing, the Commission again asked how the Companies will address the issue of outages and the target revenues. The Companies responded in Attachment 8 to their responses to *Questions from Panel Hearings Held on June 29 to July 1, 2009,* filed July 13, 2009.

[59] Wayne Shirley, Jim Lazar, and Frederick Weston, *Revenue Decoupling: Standards and Criteria*, Regulatory Assistance Project, June 30 2008.

[60] There are other differentiating factors among the service territories, which have been discussed in service reliability investigations. For example, the larger area of HELCO's service territory, and its lower

The HECO Companies have also pointed out that the inclusion of service quality standards could have unintended consequences. For example, the addition of more intermittent renewable energy resources could result in some deterioration in the outage statistics for the utilities adding the resources, as they learn to operate reliably with the additional resources. (Actual operating experience will have to be used to supplement and test operating practices based on models.) Stringent reliability standards could act as a disincentive to integrating more intermittent renewables.

Thus, if standards are introduced, the HECO Companies recommended, in their IR responses, starting with service quality monitoring programs that do not involve awards or penalties. HECO OB at 85-86.

If the Commission determines that a service quality metric is necessary even during the initial implementation period for decoupling, the HECO Companies suggested the following metric:[61]

(1) Base target revenues would be decreased if and to the extent that the Companies do not meet specified SAIDI benchmarks, calculated on a normalized basis.[62]

(2) The table below reflects the individual Companies' proposed SAIDI benchmarks,[63] if this alternative is incorporated in the RAM:

	SAIDI Benchmark
Hawaiian Electric	110 Minutes
HELCO	160 Minutes
MECO	135 Minutes

customer density, affect the travel times (and, thus, the service restoration times) for HELCO service crews.

[61] See HECO OB at 86-89.

[62] SAIDI is already reported to the Commission on an annual normalized basis.

[63] The benchmarks are based on the average of the actual, normalized SAIDI results, rounded to the nearest 5 minutes, for the period from 2004 to 2008 for each utility.

(3) The process for implementing the reliability benchmark would include estimating the target revenue loss per minute, based on the target revenue in place for that RAM year, multiplied by a factor of four. The methodology that will be used to count and report the actual SAIDI minutes will be the same as what the Companies have used since the early 1990's for Commission reporting purposes.

(4) With this type of mechanism, RBA/RAM revenues may be reduced by four times the value of sales lost above the SAIDI benchmark. For example, with a Hawaiian Electric SAIDI benchmark of 110 minutes, for the year in which Hawaiian Electric experienced an SAIDI of 120 minutes, the RBA/RAM revenues for the year would be reduced by 10 minutes (120 - 110 minutes) worth of sales revenues (excluding fuel and purchased power expenses) across all customers, multiplied by a factor of four. If the annual SAIDI was below 110 minutes, no adjustment to revenue would be required.

(5) The Companies would also return revenues for large outages normalized out of the SAIDI, if the Commission found that the Company was at fault in an outage investigation docket and ordered that the associated revenue be returned.

In its Opening Brief, DBEDT –

> proposes that for every service interruption lasting longer than the above SAIDI target goals during the year preceding the RAM year, the total target revenue requirements adjustment (excluding O&M labor, fuel and purchased power costs) for the RAM year will be reduced based on the kWh sales that would have been served during the entire outage period. For example, if HECO experienced a service interruption lasting for 120 minutes during the preceding year, the total RAM revenue requirements adjustment will be reduced by an amount equal to the total adjustment expressed on a per kWh basis for the current RAM year (i.e., calculated total RAM adjustment ÷ estimated kWh for the RAM period) multiplied by the estimate of the KWh lost or kWh not served during the entire service interruption period.

DBEDT OB at 28.

The HECO Companies maintain that DBEDT has misinterpreted the SAIDI. The system average interruption duration index (SAIDI) is a cumulative measure that sums the durations of all normalized outages for the entire year and divides by the total number of customers. Therefore, SAIDI is not representative any single interruption as DBEDT implies in its proposal above.

Each individual outage is a subset of all the outages that summed together comprises the annual SAIDI figure. The proposed performance standard represents the target year end total to which the Companies' performance would be compared to. The Companies keep track of each individual outage however it would be erroneous to compare the individual outage statistic to the year end total. Following is an example of how this calculation would be wrongfully applied if the Companies followed this process:

For the calculation we assume that the total duration of the customer outages in one month results 10,000 customers-hours.[64] Using 295,000 customers for the total number of customers served by results in the following SAIDI calculation for the month:

(10,000 customer-hours x 60 minutes/hour)/295,000 customers = 2.03 minutes

Looking at this analysis on the basis of what sort of reliability results would have to be realized monthly for a revenue adjustment to be made. Using the example of an SAIDI of 120 minutes the calculated customer outage-hours can be derived using the following:

120 minutes = 35,400,000 customer-minutes/295,000 customers

Therefore, in one month all of Hawaiian Electric's 295,000 customers would have to

[64] 10,000 customer-hours is equivalent to 10,000 customers experiencing an outage that lasted 1 hour or 5,000 customers having an outage that lasted 2 hours. What usually occurs is that there may be several outages each affecting a different number of customers that could have durations varying from a few minutes to several hours.

sustain an interruption that is two hours long. A more realistic number of customers being interrupted in a month may be about 10,000 customers and for a SAIDI or 120 minutes to be achieved it would require an outage affecting the 10,000 customers for 59 hours or about 2 ½ days. Based the information filed in the "*HECO 2008 Annual Service Reliability Report*",[65] the results for Hawaiian Electric show the average interruption duration for the customers affected by an outage (CAIDI) is 77.07 minutes (normalized) based on all the outages recorded during the year which amounted to 382,000 customer interruptions.

It is not practical to compare the on-going monthly results for SAIDI to the year end performance standard for this reason. In addition, the revenue impact of a service interruption on the Companies is the revenue associated with the kWh that was not consumed by the customers affected by the interruption. That revenue is dependant on the price of electricity in effect during the interruption based on the applicable rate schedule for each affected customer. However, since it is administratively challenging to identify the rate schedule for each affected customer and to track the price in effect at the time of the interruption for the entire year, the HECO Companies have proposed to simplify the calculation of revenue lost by dividing total annual revenue (less the revenue that recovers fuel and purchased power expenses) by the total minutes in a year to get the average revenue per minute.

This calculation is different from DBEDT's recommendation to divide the RAM adjustment by kWh not served. First, DBEDT's use of RAM has no relation to the revenue actually lost during a service interruption. As explained above the revenue lost is a function of the electricity price at the time of the interruption and has no relationship to the RAM adjustment. In addition, DBEDT calculates the kWh lost during each interruption by using the

[65] The "HECO 2008 Annual Service Reliability Report" was filed with the Commission on May 7, 2009.

recorded system kW at the start of the service interruption times the interruption duration. (DBEDT OB at 29) The system kW measures the demand by all customers not the specific demand of the customers affected by the outage. The vast majority of service interruptions affect a small fraction of the total customers and therefore the load lost is only a fraction of the total system demand. Thus, the use of system kW over-estimates the demand lost during a service interruption and is not an appropriate measure to use to derive kWh lost.

2. HCEI Performance Metrics

The proposed RAM tariff provision includes the following statement: "This mechanism is subject to review and continuation, termination or modification in the utility's next base rate case proceeding, upon a showing by the utility and finding by the Commission that continuation or modification is appropriate. As part of its submitted testimony in the base rate case, the Company will include a summary report on the status of certain HCEI initiatives." Exhibit B (page 1) to Joint FSOP. In the report, the Companies have agreed to provide details on the status of HCEI initiatives such as New NEM (megawatt ("MW") and customers), the amount of new renewable energy purchased under the FIT (MW or kWh) when effective, the increase in other renewable/nonfossil-based energy generation (MW or kWh), ("HCEI Status Report") as part of its testimony and exhibits in the next cycle of rate cases, in which the Commission will determine if the decoupling mechanism and its RBA or RAM elements should be continued, modified, or terminated. See HECO OB at 76, 81-82.

The proposal to submit the summary report was included in response to proposals by DBEDT, Blue Planet and HREA to "adjust" target RAM revenue requirements based on performance metrics related to the HECO Companies' commitments under the Energy Agreement." See HECO OB at 77.

These parties have taken the position that there should be a direct link between the revenues received by the HECO Companies under the RAM, and their achievement of the objectives of their commitments in Energy Agreement. In effect, they are attempting to make the availability of the RAM the *quid pro quo* for the commitments.[66] They have then proposed various metrics to attempt to measure achievement of the commitments, and have proposed reductions in the RAM revenues if the metrics are not achieved.

For example, DBEDT[67] and Blue Planet[68] initially proposed performance metrics that envisioned tying decoupling revenue collection to measurement of: the number of New NEM (MW or customers), the number of Pay-As-You-Save ("PAYS") program participants (MW or customers), the amount of New Renewable Energy purchased under the FIT (MW or kWh), the increase in other renewable/nonfossil-based energy generation (MW or kWh), the amount of decrease in fossil oil used during the year, and the amount of increase in energy savings (kWh) resulting from energy efficiency programs and demand-side programs. In its opening brief, DBEDT has amended its performance metrics to remove metrics based on initiatives pending Commission approval and now propose that the target goals include the addition of new MW from NEM, addition of MW of renewable energy, and the number of new net energy customers interconnected during the year.[69] In its Opening Brief, Blue Planet proposed a Clean Energy Utilization Performance Incentive Mechanism which is proposed to measure the annual improvement in percent of total energy requirements supplied by clean energy resources.[70] Based on certain assumptions and a goal that RPS is modified to be 70% by 2030 and there is no

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[66] See closing statement of HSEA, Tr. (7/1/09) at 709 (Duda); see also HDA OB at 19-21.
[67] See DBEDT's Opening Statement of Position on a Decoupling Mechanism for HECO/HELCO/MECO, page 7, filed March 30, 2009 and DBEDT's response to CA/DBEDT-IR-3, filed April 15, 2009.
[68] See Blue Planet's response to CA/BPF-IR-1, pages 1-2, filed April 15, 2009.
[69] DBEDT OB, filed September 8, 2009 at 20.
[70] Blue Planet OB, filed September 8, 2009 at 22.

Energy Efficiency Portfolio Standard ("EEPS"), HREA initially proposed two approaches to performance measurement: (1) a straight line approach based on an annual additional RPS goal of 2.75%, and (2) a Specific Projects/Activities approach.[71]

The concerns with these "HCEI Performance Metrics" proposals have been documented, most recently in pages 76 to 81 of the HECO Companies' Opening Brief.

The Companies position has been that tying a "performance-based" indexing of HCEI goals to the RAM is not necessary, because (1) the RAM will be reviewed in each of the HECO Companies' rate cases subsequent to their respective 2009 test year rate case in which decoupling will be implemented, (2) there are mechanisms in the Joint Decoupling Proposal for the review and discontinuance, if appropriate, of the decoupling mechanism, and (3) the RPS Framework includes de facto enforcement and penalty provisions should the Companies fail to make adequate progress toward the renewable energy goals. See HECO OB at 79.

The renewable energy goals in the Energy Agreement have been enacted into law, with the support of the HECO Companies, in the form of Act 155, which amended the RPS law. The RPS law has its own enforcement mechanism, and the Commission had adopted a penalty framework to supplement the RPS law, in Docket No. 2007-0008. Any "performance-based" indexing of HCEI goals to the RAM should be consistent with the enforcement, penalty and mitigation measures that are already contained in the RPS law, and in the Framework for Renewable Portfolio Standards (December 20, 2007) and penalty provisions promulgated by the Commission pursuant to the RPS law in Docket No. 2007-0008. See Decision and Order No. 23912, issued December 21, 2007, and *Order Relating to RPS Penalties*, issued December 19, 2008.

[71] See HREA's response to CA/HREA-IR-1, filed April 13, 2009.

Any such provision should also take into consideration that adding renewable resources to the system is often "lumpy", yet takes a considerable amount of effort and time to complete. These efforts include the evaluation of system grid impacts, determination of resource value (pricing), prudence reviews, and contract negotiations. These preparatory efforts are unseen and difficult to measure, but are critical to the Companies' progress toward HCEI goals. In fact, several of the Energy Agreement initiatives have already been initiated. See HECO OB at 79-80.

However, as noted above, Blue Planet and DBEDT have proposed a new set of performance metrics in their opening briefs. Noting that there is very little agreement among the parties regarding the performance metric issue, HDA has proposed that the Commission take advantage of immediate opportunities by issuing an interim decision and order in the instant docket approving the RBA and RAM for Hawaiian Electric and continuing the decoupling proceeding to address the performance metric issue along with other decoupling issues.[72] In general, the Companies support HDA's proposal, as discussed earlier.

Because of the strong desire of some of the parties to directly link accomplishment of RPS goals or commitments in the Energy Agreement to the HECO Companies' receipt of revenues under the proposed RAM, the Companies are willing to continue the dialogue with the other parties regarding the linkage between accomplishment of RPS goals to decoupling as long as both award and penalty provisions are included in the performance incentive mechanism and the performance incentive mechanism is consistent with the RPS law as amended by Act 155 (2009). Therefore, the HECO Companies now generally support the adoption of some type of broad-based clean energy[73] performance incentive mechanism in this proceeding, subject to

[72] HDA OB 7-8.
[73] Defined as "Renewable Electrical Energy", HRS § 269-91.

agreement on the specific mechanism and its details.

The HECO Companies are willing to continue the dialogue with the other parties to discuss the performance incentive mechanism ("PIM") such that the Commission may defer a decision on the PIM until the issue is thoroughly evaluated by the parties. The Companies propose that a stipulated procedural schedule for the continued dialogue be filed within 14 days of an interim decision and order in this docket, which would include the convening of a workshop to discuss the PIM within 60 days of the interim decision and order. The procedural order also would identify the filing of final statements of position by the parties no later than June 30, 2010 so they can be "incorporated" or referenced in the Hawaiian Electric 2011 rate case. The procedural schedule would also request that the Commission issue its final order in the decoupling docket that addresses the PIM issue, among others, no later than December 31, 2010. A final order by this date would allow the implementation of a RAM beginning January 2011 for both HELCO and MECO, if the RAM for those companies had not already been approved in the interim decision and order.

DBEDT's Proposed HCEI Performance Metrics

In its opening brief, DBEDT revised its performance measure proposal to adjust Hawaiian Electric's RAM[74] for the MWs of new NEM added, MWs of new renewable energy (excluding NEM) added, and number of new NEM customers interconnected with a year.[75] DBEDT continues to maintain that "the achievement of these performance measures are all within HECO's control . . . ."[76]

The HECO Companies and Consumer Advocate's FSOP points out that (1) certain

[74] DBEDT's revised proposal in its OB does not specify which proposed RAM or whether both rate base RAM and O&M RAM as proposed by HECO and the CA would be subject to their proposed performance measure adjustment.
[75] DBEDT OB at 19 through 26.
[76] DBEDT OB at 21.

programs and measures are outside the control of the HECO Companies, (2) the HECO Companies agreed that the RPS is an effective structure to track the Companies' obligation to add renewable energy, (3) there are existing mechanisms in the Energy Agreement which are reinforced in Joint Decoupling Proposal and the FSOP to ensure that the RAM will be reviewed so that it is "operating in the interest of the ratepayers, and (4) tying performance metrics to the RAM is inconsistent with the purpose of the decoupling provision, as reflected in the Energy Agreement."

Although DBEDT's has most recently eliminated performance measures based upon then yet-to-be approved programs such as FIT and PV Host programs in its opening brief, the revised performance measure proposal remains based on measures that are beyond Hawaiian Electric's control. DBEDT claims that, because Hawaiian Electric controls the interconnection standards and procedures for interconnecting net energy metered customers, Hawaiian Electric has control over the number of NEM installations (apparently in both MWs and number of customers).[77] In fact, the number of NEM installations and MW installation is dependent upon the interest and decisions by customers to pursue the installation of a PV system and enter into a NEM arrangement with the utility versus alternatives such as installing PV systems sized only to reduce their electricity demand from the utility and not enter into a NEM arrangement or to develop a PV system to sell power to the utility under a PPA. This customer decision is greatly dependent on the load profile of the customer and the energy output profile of the DG system, the state and federal tax incentives, credits and subsidies available to these customers, and the amount of rooftop or land space available at each site. In addition, customer decisions are also based upon the price of PV and other NEM-qualifying generation technologies (with or without

[77] DBEDT OB at 21.

any tax credits and other subsidies) compared to the retail price of electricity for their rate schedule.

DBEDT's performance measure proposal for new renewable power excluding NEM appears to be based on the addition of new MW of renewable energy on the system.[78] Although DBEDT contends that Hawaiian Electric is in the "driver's seat" in contract negotiations for purchase power contracts, and controls the success of whether or not a purchase power proposal from a developer actually results in a purchased power contract,[79] there is no direct relationship between simply signing a power purchase agreement ("PPA") and the addition of new renewable power.

There are a number of factors beyond Hawaiian Electric's control that impact whether or not a PPA is executed and if an executed PPA results in the successful development of a renewable energy project. First, a developer must either provide an unsolicited proposal or respond to an RFP for energy in order for Hawaiian Electric to begin evaluating a project proposal and negotiate a PPA. Second, a successful negotiation of a PPA is dependent on the willingness and ability of the developer to invest in preliminary siting, permitting, and engineering to develop a project proposal with sufficient detail to allow the utility to evaluate key parameters of the project, including but not limited to necessary system interconnections, performance standards, operational impacts of the proposed project and the evaluated benefits of the project. Third, successful negotiation of a PPA for many renewable technologies is dependent on the availability of qualifying tax credits or tax incentives which can have a tremendous impact on the level of renewable energy development. The American Wind Energy Association developed a summary of historical impact of production tax credit expiration on

[78] DBEDT OB at 20.
[79] DBEDT OB at 21.

annual installation of wind capacity which identified a 93% drop, a 73% drop, and a 77% drop of wind firm installations following the expiration of production tax credits at the end of 1999, 2001, and 2003, respectively.[80]

Fourth, signing a PPA does not guarantee a successful development of a project. Successful development of the project is contingent upon obtaining financing of the project. The financial crisis which began in third quarter of 2008 illustrates the volatility of the project capital and bank markets and the impact that has on project development. Large US players in project financing such as AIG, Lehman Brothers and Wachovia Corp have either gone bankrupt or have significantly scaled back or exited wind farm and other renewable energy project financing. The significant reduction in financing options has had a large impact on wind farm and other renewable energy project developments in 2009. In addition, the successful development of a renewable energy project is contingent upon the developer obtaining all necessary permits and approvals for the construction and operation of a generating facility, which include but are not limited to land use permits, conditional use permits, covered source permits, water supply and wastewater permits, noise variance permits, construction permits, NPDES permits, SMA permits, and building permits. Delays or denials of these permits can significantly delay the timing and size of a proposed generation project.

In addition, DBEDT's proposed performance measures are based on the number of new NEM customers and MWs of NEM and non-NEM renewable energy additions. These metrics are inconsistent with the RPS law's formula to determine the MWhs of renewable energy generation. DBEDT's performance metrics would have the consequence of encouraging the utility to install many NEM and other RE installations of high MW nameplate capacity that may

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[80] AWWA website: http://www.awea.org/pubs/factsheets/ptc_fact_sheet.pdf.

not provide much renewable energy generation. It also encourages the addition of such projects without any regard to the relative cost of such projects compared with other renewable energy projects with lower nameplate capacity but with higher capacity factor and greater annual MWh generation.

As a result, a broad-based measure is preferable to one tied to specific technoligies.

<u>Blue Planet's Proposed "Clean Energy Utilization" Performance Incentive Metric</u>

In its opening brief, Blue Planet proposed a Clean Energy Utilization Performance Incentive Metric ("CEU PIM").[81]

Blue Planet's CEU PIM proposes a RAM rate adjustment of +/-$7M, +/-$2M, and +/-$2M for Hawaiian Electric, HELCO and MECO, respectively, based upon each company's annual change in percentage utilization of clean energy. The CEU PIM target reflects about a 1% annual increase in the CEU ratio. The CEU PIM is proposed as a symmetrical mechanism "to reward excellent improvement and penalize poor performance with respect to achieving Hawaii energy objectives."[82] Although not clear, the CEU PIM proposal suggests that rewards for achieving results higher than the target would not be subject to the earnings sharing mechanism since the rewards are calibrated to changes in the individual companies' ROEs. Also, Blue Planet states that, "In the event the Commission reduces the HECO Companies' ROE in a rate cast to reflect the lower cost of equity capital, it may be appropriate for the HECO Companies to have recourse to a performance incentive mechanism as may be adopted by the Commission. Such a mechanism may allow the HECO Companies to restore and increase profits based upon their successful achievement the Hawaii clean energy law and policy

[81] Blue Planet OB at 22.
[82] Blue Planet at 24

objectives [sic]".[83]

Blue Planet contends that "absent a PIM, the Hawaii RPS law provides no incentives."[84] However, the Commission does have the authority to impose penalties upon utilities for failure to achieve an RPS target.[85]

Blue Planet also contends that a PIM can be utilized to encourage additional and more precise quantification of progress or lack of progress in achieving RPS objectives.[86] However, since 2003, the HECO Companies have filed annual updates on the RPS percentage individually and on a consolidated basis that provide very detailed quantifications of RPS components. In contrast, Blue Planet's proposed CEU PIM formula differs from the RPS formula, so it is unclear how the proposed CEU PIM, as proposed, provides "precise quantification of progress or lack of progress in achieving RPS objectives."

In addition, Blue Planet's proposed CEU PIM is based on annual performance relative to the prior year. Because most MWhs of new renewable energy generation are added in blocks (such as when a central-station wind farm or geothermal facility is placed into service) with periods of less and often no increase in between these blocks, the CEU PIM would reward the utility in the first year of operation, but could penalize the utility in the second year of operation.[87] In an informal discussion with Blue Planet, the Companies raised the issue of the "lumpiness" of results as one of the primary concerns with the CEU PIM.

3. Impact of Decoupling on Cost of Common Equity[88]

A remunerative decoupling mechanism (i.e., one which includes a sales decoupling

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[83] Blue Planet OB at 15

[84] Blue Planet OB at 20.

[85] See the Commission's *Order Relating to RPS Penalties*, issued December 19, 2008 in Docket No. 2007-0008.

[86] Blue Planet OB at 21.

[87] Blue Planet's proposed CEU PIM has a neutral impact if the CEU percentage increases at 1% per year.

[88] See HECO OB at 100-05 and Exhibit E.

mechanism), and a revenue adjustment mechanism that reasonably mimics cost-of-service ratemaking) should have a beneficial impact on a utility's required cost of common equity. Hawaiian Electric's expert on the cost of common equity (in its on-going 2009 test year rate case) has estimated that impact at 25 basis points.[89] That impact should be considered, along with other factors that impact the utility's business, financial and overall investment, risks in determining the "fair" rate of return on common equity used in a rate case to determine the utility's revenue requirements.

If an appropriate decoupling mechanism (i.e., a mechanism that decouples sales from revenues and includes a fair revenue adjustment mechanism, to recover increased costs), then the utility's revenues should be more stable than they would be without such a mechanism, and its earnings could be more stable. Taken in isolation, this would mean a lower level of investment risk than an entity with the same level of earnings, but more earnings variation, would have. However, the decoupling mechanism is being proposed in the context of the total requirements and commitments set forth in Act 155 and the Energy Agreement[90] – and is not being proposed in isolation. There is no indication that investors will perceive a lower level of investment risk as a result of the commitments and requirements in Act 155 and the Energy Agreement taken altogether.

Other parties suggest that the Companies' rate of return on common equity should be adjusted downward if decoupling is implemented. See, e.g., HDA OB at 38; Blue Planet OB at

[89] In the current HECO 2009 Rate Case, Dr. Morin (HECO RT-19) also indicates that it is currently speculative as to whether, and if so how, decoupling and the RAM will affect the Hawaiian Electric's risk profile. He recommends a range of 11.0%-11.25% assuming the Consumer Advocate and HECO Companies' sales decoupling and RAM proposal is approved, and a range of 11.25%-11.5% otherwise. (See HECO RT-19, filed May 22, 2009, in Docket No. 2008-0083, at 68.)

[90] See Exhibit F to the HECO Companies' Opening Brief.

15.[91] This issue should, however, be reviewed in the context of why this proceeding decoupling is being considered at this time.[92] In the Energy Agreement, the HECO Companies have (2) agreed to support energy efficiency programs, DG, and deployment of substantial indigenous renewable energy sources (wind and solar) and undersea cable systems to deliver wind generated power from Lanai or Molokai to Oahu, and (2) have committed to biofueling, a RPS, greening transportation, displacement of fossil fuel energy, retirement of older and less-efficient fossil fuel-fired firm capacity generating units, and deployment of the advanced metering infrastructure and seawater air conditioning. These initiatives require significant financial resources due to additional expenses and capital requirements, and involve new technologies. As a result, the initiatives may actually increase the Companies' financial risk since many of the technologies that are identified in the Energy Agreement are still in early stages of their development. See HECO Scoping Paper Comment #10.

Viewed in this context, decoupling can be viewed as a means of avoiding the need to raise the Companies' allowed rate of return to attract additional financial resources. As stated in the Energy Agreement: "The transition to Hawaii's clean energy future can be facilitated by modifying utility ratemaking with a decoupling mechanism that fits the unique characteristics of Hawaii's service territory and cost structure, and removes the barriers for the utilities to pursue aggressive demand-response and load management programs, and customer-owned or third-party-owned renewable energy systems, and gives the utilities an opportunity to achieve fair

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[91] Blue Planet also suggests that: "In the event the Commission reduces the HECO Companies' ROE in a rate case to reflect the lower cost of equity capital, it may be appropriate for the HECO Companies to have recourse to a performance incentive mechanism as may be adopted by the Commission." Blue Planet OB at 15.

[92] Utilities in other jurisdictions have implemented decoupling in a "business as usual" operating environment amid declining sales; but never, to the HECO Companies' knowledge, have taken on the risks associated with the numerous massive and substantive projects similar to those required to carry out their obligations under Act 155 and the Energy Agreement at the same time. See Response to NRRI Appendix 2 Question #7.

rates of return."

An appropriate decoupling mechanism lowers the risk of the HECO Companies by ensuring that revenue equals the revenue requirement, but it also stabilizes consumer expenditures and ensures that consumer expenditures equals the revenue requirement. So, in a year with a booming tourist economy and/or unusually hot weather, customers do not pay any more for base rate services; nor do the Companies collect any more revenue for the increased usage. Similarly, in a year with a depressed economy and/or unusually cool weather, customers do not pay any less for base rate services; nor do the Companies collect any less revenue for the lower usage.

4. **Impact of Decoupling on Customers**[93]

The sales decoupling mechanism establishes a target revenue requirement (i.e., sales revenue forecast used in the rate case being used as the base year). The impact of a sales decoupling mechanism on customers' rates depends on whether electric sales revenues are higher or lower than the target revenue requirement.[94] Mr. Freedman testified that:

> The decoupling part of the process itself is revenue neutral. Sales go up; sales go down. What we're trying to do is make sure we have a balance of recovery of fixed costs, just as we would with more frequent rate cases. But we are removing some bad disincentives and we're also still providing some value in reduced risk to the company. It can be a net gain in terms of by assuring the company of recovery of revenues.

Tr. (7/1/09) 721-22 (HDA's closing statement).

Hawaiian Electric is using its 2009 test year as its base year. The sales revenue forecast used in Hawaiian Electric's 2009 test year did not fully capture the impact of the current

[93] See HECO OB at 22-25.

[94] The direct impact of sales decoupling could, under certain circumstances, produce reduced customer bills, for instance, when overall utility sales exceed test year projected levels. This might occur in periods of economic expansion as the HECO Companies have experienced in the past or after periods of extremely hot weather, e.g., during periods when air conditioning loads serve to increase electric demand. See the HECO Companies' response to the NRRI Scoping Paper, Appendix 2, Question 2, subpart 2.4.

recession. For Hawaiian Electric, an alternative to the sales decoupling mechanism would be to obtain the needed revenue requirement escalation through a 2010 test year rate case. However, this approach would involve a high level of regulatory cost at a time when the implementation of the Energy Agreement will be raising a host of new issues meriting regulatory oversight.

In the long run, clean energy initiatives should decrease and even eliminate sales growth. Sales decoupling removes a utility's disincentive to reduce sales and, hence, to promote energy efficiency and other programs that reduce kWh sales. By removing that barrier for the HECO Companies, the decoupling proposal may, at least indirectly, promote energy efficiency opportunities and encourage customers to be energy efficient. In addition, sales decoupling helps to provide revenue stability through the target revenue requirements and revenue balancing accounts.

The RAM is designed to adjust the target revenue requirement level each year in order to compensate utilities for changes in O&M costs and the return on and return of investments in infrastructure between rate cases , which results in a rate increase in the absence of deflation.

Annual or biannual rate cases for the Companies are an alternative means to obtain the needed revenue requirement escalation under a decoupling plan without a RAM. As previously discussed, this approach would involve a high level of regulatory cost at a time when the implementation of the new RPS enacted by Act 155 (2009) and the Energy Agreement will be raising a host of new issues meriting regulatory oversight, and there is also concern that annual rate cases would not be sufficiently compensatory.

From a customer standpoint, the overall impact on prices would generally be the same, whether price increases result from decoupling or from rate cases. However, decoupling does include the potential to reduce a utility's cost of common equity (from what it would have been without decoupling), and to reduce rate case costs. These cost reductions would result in somewhat lower rates with decoupling, at least in the long run.

Rates could be lower under the rate case model (without decoupling) if regulatory lag prevents the utility from implementing rates that fully cover its costs. Such a result, however, would severely damage the utility's financial integrity and ability to attract capitol - and would be detrimental to both the utility and its customers.

III. CONCLUSION

Based on the foregoing and the entire record herein, the HECO Companies respectfully request that the Commission approve the Joint Decoupling Proposal, with such modifications as are determined to be reasonable and in the public interest.

It is essential and in the public interest that the HECO Companies be allowed to implement decoupling (including sales decoupling and a mechanism to adjust revenues between rate cases) at this time.

DATED: Honolulu, Hawaii, September 29, 2009.

THOMAS W. WILLIAMS, JR.
PETER Y. KIKUTA
DAMON L. SCHMIDT

Attorneys for
HAWAIIAN ELECTRIC COMPANY, INC.,
HAWAII ELECTRIC LIGHT COMPANY, INC., and
MAUI ELECTRIC COMPANY, LIMITED

EXHIBIT A

DECOUPLING MECHANISMS

I. Introduction

Revenue decoupling is an approach to utility regulation in which the link that exists under traditional regulation between a company's earnings and the volume of its deliveries is relaxed or broken. The linkage exists due to differences between the way a utility's cost are incurred and how its base rate revenues are generated. Base rate revenues are those that compensate a utility for the cost of its non-energy inputs, which comprise of capital, labor, materials, and services. Most utilities obtain the bulk of these revenues from volumetric charges, so when things like conservation, customer-sited distributed generation or utility energy efficiency programs increase and volume decreases, the utility's profits erode and the need for a rate case increases. See PEG Report[1] at 6.

II. General Decoupling Approaches

A. True-Up Decoupling

One approach to revenue decoupling is called the true-up approach. The basic idea is a regularly scheduled sequence of rate adjustments that cause a company's actual revenues to track its revenue requirement approved in its last rate case more closely. True-up mechanisms typically involve a balancing account in which the difference between actual revenue collected and the revenue requirement is entered. The accumulated net balance, together with any interest that may be accrued, provides the basis for a periodic rate adjustment. For example, the annual balance that accumulates at the end of the year might be added to the revenue requirement for the following year. In the typical "two way" decoupling mechanism, the rate adjustments to clear the balancing account are likely to take the form of surcharges in some years and credits in others. PEG Report at 7.

Decoupling true-ups are often applied to all customer classes. However, some plans decouple the revenue requirements of certain customer classes selectively. In these plans, decoupling typically applies to residential and/or commercial customers and excludes industrial customers. PEG Report at 7.

The true-up approach to decoupling also typically involves a revenue adjustment mechanism ("RAM") to escalate the revenue requirement for changes in business conditions that "drive" the cost of base rate inputs. This task is sometimes referred to as "recoupling". If a utility's billing determinants are growing, rates will actually decline with decoupling absent some form of revenue requirement escalation despite the fact that the cost of service normally rises due to input price inflation and output growth. Rate cases are another means of attaining attrition relief under true-up mechanisms. The need for frequent rate cases will be exacerbated under conditions of brisk input price inflation and mounting investment needs. PEG Report at 7.

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[1] Dr. Mark Lowry, *Revenue Decoupling for Hawaiian Electric Companies* ("PEG Report"), Pacific Economics Group, LLC ("PEG"), filed February 3, 2009.

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B. Straight Fixed Variable Pricing

Another approach to revenue decoupling is straight fixed variable ("SFV") pricing. This approach redesigns rates to better reflect the short-run impact that sales volumes, the number of customers served, maximum demand, and other billing determinants have on utility cost. Full decoupling can be achieved when volumetric charges are set at the short-run marginal cost of volume growth and the balance of revenue is recovered from other charges. Customer charges and/or demand charges are commonly raised to achieve this goal in a revenue-neutral manner.[2] PEG Report at 7.

III. Revenue Adjustment Mechanisms

A sales decoupling mechanism alone (without a RAM mechanism) is insufficient to compensate a utility for increases in utility costs or infrastructure investments between rate cases.[3] As a result, the mechanism used to escalate the revenue requirement is one of the most important features of a true-up approach to decoupling. RAMs can substitute for rate cases as a means to adjust utility rates for trends in input prices, demand, and other external business conditions that affect utility earnings. This makes it possible to extend the period between rate cases without relaxing the just and reasonable standard for regulation. The objectives of a RAM are: (1) to partially recover between rate cases the increases in costs that are fixed in the short term due to inflation, changes in utility output, and investments in utility infrastructure; and (2) to maintain the financial health of the company.

A. Forms of RAM

There are a number of forms of RAMs, which can generally be broken down into three categories: (1) formulaic RAMs (e.g., full indexation, revenue per customer freeze, inflation only, and revenue per customer index RAMs); (2) all forecast RAMs; and (3) hybrid RAMs.[4]

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[2] The PEG Report stated that the SFV approach to decoupling is especially advantageous compared to the true up approach under the following conditions:

> (1) The long run marginal cost to the utility of a unit sold is not far above the short run marginal cost. This is more likely to be true for a gas or electric power distributor than for a vertically integrated electric utility.
>
> (2) The additional marginal cost of any social problems engendered by the sale of energy is small.
>
> (3) The RAM is not designed to reduce the frequency of rate cases.

These conditions do not hold true for the HECO Companies.
PEG Report at 55.

In addition, Dr. Lowry testified that there are many negatives to the approach and one benefit. The benefit is that it is easy to implement and then operate. The downsides of the SFV approach include that it is a step backwards to encouraging energy efficiency. Recovering virtually all of the fixed costs through fixed charges or at least nonvolumetric charges, increases the payback period for energy efficiency projects. In addition, the SFV approach has not been used in the power industry. The only use of the SFV approach has been in the gas distribution industry. See Tr. (6/29/09) at 82-84 (Lowry); see also HECO Companies' response to PUC-IR-5.

[3] See Section I.C.3 of the Companies' Opening Brief.

[4] Dr. Mark Lowry explored significant forms of RAM in the PEG Report.

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1. Formulaic RAMs

One of the general categories of RAMs is composed of formulaic RAMs. Within this category, the full indexation approach to RAM design adjusts the revenue requirement formulaically to reflect new information (information obtained after the decoupling plan starts) about the business conditions that drive utility cost. Some of these formulaic RAMs make adjustments for price inflation and output growth. Other formulaic RAMs escalate the revenue requirement only for price inflation – "inflation only" RAMs. PEG Report at 8.

Another class of formulaic RAMs escalates the revenue requirement only for customer growth. Since this latter approach effectively freezes the revenue requirement per customer it is often called the revenue per customer ("RPC") freeze approach.[5] An RPC freeze may apply to the total revenue per customer, or alternatively, to individual rate classes.[6] See PEG Report at 8. However, the RPC methodology (proposed by HDA) does not achieve the objectives of a RAM.

First, the RPC methodology is only concerned with the growth in fixed costs between rate cases and expressly removes test year fuel and purchased power expenses from the determination of RPC amounts. As the proposed RPC methodology does not track the utilities' fixed cost as well as the RAM jointly proposed by HECO Companies and the Consumer Advocate, the adoption of the RPC methodology would have an adverse effect on the procurement of more expensive non fossil fuel-based facilities and electricity.[7]

Second, the RPC does not serve as a proxy for changes in fixed costs. Therefore, revenues under the RPC would not improve the Companies' financial position. Whether or not the utilities would be able to maintain their current ability to attract capital, on reasonable terms, in amounts sufficient to fulfill the utility's statutory obligations results from the utility's operating environment in totality; therefore, the impact of the RPC is difficult to isolate.[8]

Third, the total cost of serving the utility's customers will be established in a general rate case proceeding where the utility's expenses and revenue requirements will be determined to be just and reasonable by the Commission. The RPC methodology would serve to limit the utilities' revenue growth in non rate-case years which may result in more frequent rate cases.[9]

Fourth, the RPC methodology is a common attrition methodology employed by natural gas local distribution utilities where a large portion of fixed costs are tied directly to, and vary

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[5] The RPC approach was proposed by HDA in its response to NRRI Appendix 2 Question 2 and reiterated in its Opening Statement of Position.

[6] The RPC approach applied to individual rate classes was featured in a presentation made by Wayne Shirley of the Regulatory Assistance Project ("RAP") in Honolulu in April 2008.

[7] HECO Companies' response to PUC-IR-46 at 2. Mr. Freedman acknowledged that the RPC approach does not track fixed costs as well as the proposed RAM mechanism. Tr. (6/30/09) at 448 (Freedman).

[8] HECO Companies' response to PUC-IR-46 at 2.

[9] HECO Companies' response to PUC-IR-46 at 3-4.

with the number of customers.[10] The Companies' fixed costs are not related to the number of customers. Thus, as a means to ensure that the Companies remain financially healthy between rate cases, the RPC methodology will not perform as well as the RAM methodology that is jointly proposed by the Companies and the Consumer Advocate.[11]

The RPC does not escalate a utility's revenue requirement for input price inflation and productivity growth. As such, it provides inadequate attrition relief because input price inflation is usually well in excess of productivity growth.[12] Shirley, Lazar, and Weston, in their recent paper on decoupling for the Minnesota Public Utilities Commission, describe a "well designed decoupling program" as "one that possibly allows for adjustments according to changes in short-run drivers such as numbers of customers, inflation, and productivity."[13]

To avoid financial attrition, utilities operating under RPC freezes file rate cases more frequently. This raises regulatory cost and can compromise utility cost performance. A RAM that provides relief for inflation as well as customer and activity growth makes it possible to simultaneously reduce regulatory cost and improve utility performance. That is why most RAMs that have been implemented in the U.S. and other countries over the years have not employed an RPC freeze approach.[14]

Mr. Freedman, HDA's panelist, testified that a utility would be better off financially under a RAM approach than under an RPC approach.[15] RPC freezes are substantially uncompensatory as the primary basis for adjusting utility revenue requirements. This is a particular concern in states with historic test years since the test year revenue requirement will already reflect dated inflation assumptions. The inadequacy of RPC freezes as mechanisms for full attrition relief is one of the reasons that utilities who operate under such freezes typically reserve the right to file rate cases during the decoupling plan.[16] For example, Idaho Power came in for a rate case in 2008, the second year of its decoupling plan.[17]

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[10] The fact that RPC freezes apply chiefly to gas local distribution companies makes sense since, for these utilities, such freezes will reduce the financial attrition that results from declining average use by residential and commercial customers. PEG Report at 43.

[11] HECO Companies' response to PUC-IR-46 at 2-4.

[12] The PEG Report found that the productivity trend of vertically integrated electric utilities is similar to that of the U.S. private business sector as a whole. As such, it is likely to be well below the pace of input price inflation. PEG Report at 15.

[13] Wayne Shirley, Jim Lazar, and Frederick Weston, *Revenue Decoupling*: *Standards and Criteria*, Regulatory Assistance Project, 30 June 2008 at. 9; see HECO Companies response to PUC-IR-5, and PUC-IR-16.

[14] HECO Companies' response to PUC-IR-5 at 1.

[15] Tr. (6/30/09) at 467 (Freedman).

[16] See PEG Report at 15, 72. Moskovitz and Swofford note that "The RPC decoupling method is not designed to change the length of time between utility rate cases. The utility remains free to initiate a general rate case if its financial condition requires it." See David Moskovitz and Gary B. Swofford, "Revenue per Customer Decoupling" in Steven M. Nadel, Michael W. Reid and David R. Wolcott, eds. *Regulatory Incentives for Demand-Side Management*. Washington, D.C. and Berkeley CA, American Council for an Energy Efficient Economy, 1992.

[17] PEG Report at 43; Tr. (6/30/09) at 461-62 (Lowry).

Idaho Power is the only vertically integrated utility in the United States that operates under an RPC freeze mechanism. In addition, of the 16 currently approved and active decoupling plans for electric utilities, seven have an RPC mechanism. The nine others have some type of a broad based attrition mechanism like the one proposed by the HECO Companies and the Consumer Advocate. Further, of the five most recently approved decoupling mechanisms, four do not feature an RPC freeze mechanism, and of the five decoupling plans currently being considered outside of Hawaii, only two (both in Michigan) have an RPC freeze component.[18]

The RPC approach has been primarily employed for gas local distribution utilities. In addition, the RPC approach has been applied to provide some measure of attrition relief based on the assumption that utility costs bear some direct relationship through time to the numbers of customers being served. However, (1) such an assumption has been rarely proven, and (2) use of the RPC approach may be questionable absent a showing that there is that correlation between number of customers served and changes in costs between test years.[19]

The RPC approach does not solve all the concerns that the hybrid RAM (discussed below) is trying to solve.[20] If the Commission's objectives are to (1) develop a comprehensive solution to address declining sales which results in a shortfall of revenue, and (2) keep the utilities relatively strong financially, then the RPC approach does not deliver a package that would accomplish those objectives.[21]

2. All Forecast RAMs

All forecast RAMs are a second broad category of RAMs, based solely on forecasts of future cost that are made prior to the start of the decoupling plan. This is tantamount to a rate case with multiple forward test years. The revenue requirement trajectories produced by this approach typically display a "stairstep" pattern. The stairsteps may reflect expected changes in business conditions during the decoupling plan but there are no automatic adjustments to the revenue requirement in the event that business conditions turn out to be different from those that were expected. The cost forecasts that provide the basis for stairsteps are frequently made using formulas similar to those used in formulaic RAMs. For example, a forecast of growth in operation and maintenance ("O&M") expenses might be based formulaically on forecasts of O&M price inflation and/or customer growth that are available at the time that the RAM is designed. PEG Report at 9.

All forecast RAMs should take account of inflation, productivity, and customer growth trends to be fully compensatory. All forecast RAMs have several advantages in accomplishing this goal. One is that they can sidestep the complex issue of input price and productivity measurement. Complexity is especially great in the measurement of capital cost. Many participants in the regulatory arena are unfamiliar with the measurement of capital price and quantity trends. Another advantage of all forecast RAMs stems from the fact that full indexation

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[18] See Tr. (6/30/09) at 461-62 (Lowry).
[19] See Tr. (6/30/09) at 456 (Brosch).
[20] See Tr. (6/30/09) at 467, 468 (Freedman).
[21] Tr. (6/30/09) at 441-42 (Freedman).

RAMs usually reflect a judgment concerning long-run industry productivity trends. The resultant productivity targets are often unsuitable for funding the surges in major plant additions that utilities sometimes make. PEG Report at 15, 18.

The chief downside to using all forecast RAMs is their rigidity. Inflation and other business conditions that affect utility cost do not always turn out as forecasted. The result can be windfall gains or losses for utilities and higher operating risk. PEG Report at 18.

3. Hybrid RAMs

A third broad class of RAMs is hybrid RAMs, which employ a mix of real-time formulaic adjustments and forecasting methods. The term "hybrid" refers to the combination of formulaic and forecast approaches to derive the annual change in target revenue requirements. In North America, hybrid RAMs most commonly feature real-time formulaic adjustments for O&M expenses. Some also feature adjustments for plant additions. The target rate of return on rate base is sometimes subject to separate adjustment during the term of the decoupling plan. Fixed forecasts are used for the cost of older plant using conventional cost of service methods. PEG Report at 9.

The general approach to hybrid RAM design has a number of advantages. Indexing is used where it is least controversial, as in the escalation of O&M expenses. There is no need for the complex calculations needed to measure input price and productivity trends for utility plant. The formulas permit adjustments for new information about inflation. The treatment of capital cost is flexible enough to accommodate surges in plant additions. PEG Report at 18.

The hybrid RAM approach stabilizes revenue in the face of volume fluctuations that result, in the short run, from changes in weather and local economic conditions. This helps to reduce risk. PEG Report at 47.

As discussed further in the HECO Companies' Opening Brief, the Companies and the Consumer Advocate are proposing a hybrid RAM, in which O&M expenses are escalated using a formula that includes inflation or input cost escalators (a formulaic approach), and rate base is escalated based on a trended forecast. The hybrid RAM proposed by the HECO Companies and the Consumer Advocate is neither novel nor untested.[22] Although a variety of approaches to RAM design have been used in California since the inception of decoupling, the hybrid approach has been the most common over the years.[23]

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[22] One of the Consumer Advocate's consultants, Mr. Brosch, described the proposed decoupling mechanism as being one "that was protective of the public interest, conservative in exposure rate payers would face to increasing revenue requirements, and designed in a way that would be administratively practical." Tr. (6/29/09) at 94 (Brosch).

[23] <u>See</u> PEG Report at 23-25 (Table 2 showing hybrid RAM mechanisms implemented in California). Dr. Lowry testified that the hybrid RAM approach proposed by the HECO Companies and the Consumer Advocate is "an absolutely tried and true method that's been used a dozen times in the State of California." Tr. (6/30/09) at 462-63 (Lowry). While the hybrid RAM approach has been popular in California, the RPC freeze approach has not been implemented in California. Other established approaches to RAM design have been used in California. For example, the all forecast approach to RAM

Moreover, the hybrid RAM is the only mechanism that meets the Energy Agreement criteria, which includes a mechanism based on cost tracking indices such as those used by the California regulators, not based on customer count, and providing revenue adjustments for the differences between the amount determined in the last rate case and the current cost of operating the utility and the return on and return of ongoing capital investment. HECO Companies Initial SOP at 12.

The popularity of the hybrid RAM may be attributed to the flexibility with which it can provide relief for inflation and customer growth, under a variety of operating conditions, without complex indexing research. PEG Report at 44.

4. Other RAM Options

The Commission's July 15, 2009 information requests identified a number of possible RAM components, including (1) a revenue adjustment equal to the authorized return and depreciation on net additions related to system reliability (designated 3.a), (2) a revenue adjustment equal to the authorized return and depreciation on net additions related to customer additions (designated 3.b), (3) a revenue adjustment equal to the difference in operating and maintenance costs associated with complying with Act 155 (designated 3.c), (4) the O&M portion of the RAM proposed by the HECO Companies and the Consumer Advocate (i.e., RAM without rate base adjustments) (designated 3.d), (5) the total of items 3.a, 3.b and 3.c, (6) the total of items 3.a, 3.b and 3.d, and (7) each of the above with and without a revenue per customer ("RPC") "with reset".

The HECO Companies were asked to quantify the results for the various possible RAM components using the layout in their response to PUC-IR-14 (as revised).[24] In their responses to PUC-IR-57, filed August 24, 2009, the HECO Companies discussed the pros and cons of implementing the revenue enhancements discussed at each of 3.a (reliability investments), 3.b (customer addition investments), 3.c (Act 155 compliance O&M), and 3.d (the proposed O&M cost escalator).

The first proposed tool (3.a) would compensate the Companies for higher capital costs due to reliability investments. Investments of this type are expected to be made every year to allow the utilities to provide reliable service to their customers. This category of investment usually reflects the lion's share of the Companies' total capital budget.[25] The method of recovery for these costs as proposed in the information request[26] is advantageous to the

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design was employed in some of the earliest RAMs. PEG Report at 25-27 (Table 2), 35. California utilities have also employed the inflation only RAM approach, and the full indexing RAM approach. PEG Report at 27-28 (Table 2), 35.

[24] On July 1, 2009, during the decoupling panel hearings held on June 29 to July 1, 2009, the Commission issued PUC Hearing Exhibit 1, which posed specific questions regarding the HECO Companies' response to PUC-IR-14. The responses to these questions were provided in Attachments 1 and 2 to the HECO Companies' July 13, 2009 filing. Revised Results were filed August 7, 2009 (including modifications to PUC-IR-14 spreadsheets), and on August 13, 2009.

[25] See Companies response to PUC-IR-52

[26] The Companies' understanding of the recovery method is further discussed in their response to PUC-IR-61.

Companies since it allows the Companies to implement a surcharge on a quarterly basis, almost immediately after the plant is placed into service.[27] In addition, by only including plant that is already placed into service as the basis for the surcharge, this method of recovery addresses the potential concern that ratepayers would be paying for plant additions that are not yet used or useful.

The second proposed tool (3.b) would compensate the Companies for investments needed to serve additional customers. This would be especially welcome for HELCO and MECO, given their comparatively rapid customer growth. The advantages noted above for the reliability category of investment apply to this revenue enhancement tool as well.

The third proposed tool (3.c) would compensate the Companies for extra O&M expenses occasioned by Act 155, which raises the renewable portfolio standards for the Companies to levels that are remarkably high by national standards. The Companies understand this category of costs to be those that are not recovered from any other surcharges. There is no special provision for these O&M expenses in the Companies' proposal. A disadvantage of implementing this revenue enhancement tool is that, currently, there is no clear or consistent definition of Act 155 costs among the Companies. If this proposed tool were authorized by the Commission in the instant proceeding, there would be a need for the Consumer Advocate and Commission to assist in determining what should constitute this category of costs. Moreover, because the Companies have not historically tracked costs in this manner, new internal procedures would need to be developed and established so that Act 155 expenses (not recovered through other surcharges) would be easily identified and gathered for reporting purposes.

The fourth proposed tool (3.d) is the O&M expense escalation formula proposed by the Consumer Advocate and the HECO Companies. This would compensate the Companies for the impact that a broad range of business conditions, including input price inflation and output (e.g., customer) growth have on O&M expenses.

All four of these tools provide compensation for one or two cost drivers but none of them are individually sufficient to avoid frequent rate cases. A combination of the tools would, naturally, make an alternative RAM composed of them more compensatory. Tools 3.a and 3.b together come close to providing the needed capital cost escalation for a majority of the Companies' annual plant additions. However, tool 3.c by itself is clearly deficient as an escalator of O&M expenses.[28]

[27] Practically speaking, there would be a lag of at least three months (one quarter) to aggregate and verify the plant that is placed into service, to calculate associated rate base components such as depreciation and ADIT, prepare the filing to the Commission, allow time for the Commission and Consumer Advocate to review, and implement the surcharge.

[28] In Attachment 1 to their response to PUC-IR-61, the HECO Companies presented the returns on common equity ("ROE") and the RAM amounts associated with options 3.a, 3.b, and 3.c, with and without an "RPC with reset," as compared to the RAM amounts proposed by the Consumer Advocate and HECO Companies in their Joint FSOP.The HECO Companies set forth some qualifications regarding the calculation approach so that the comparisons could be viewed from an appropriate perspective. See HECO Companies response to PUC-IR-61 at 1-3.

While the adoption of one of the revenue enhancement tools discussed above would provide the utilities with a clear understanding of the regulator's priorities, each tool alone would not achieve the same potential for reduction of rate case frequency that would be provided by the revenue decoupling proposal submitted by the Consumer Advocate and the HECO Companies, would insert a degree of subjectivity into the process (i.e., with regards to what is the definition of Act 155 costs) and may have unintended consequences with regards to expenditures and investments made by the utilities.

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CERTIFICATE OF SERVICE

I hereby certify that I have this date served a copy of the foregoing REPLY BRIEF OF HAWAIIAN ELECTRIC COMPANY, INC., HAWAII ELECTRIC LIGHT COMPANY, INC., AND MAUI ELECTRIC COMPANY, and EXHIBIT "A", together with this CERTIFICATE OF SERVICE, as indicated below by hand delivery and/or by e-mailing a copy to the following:

Hand Delivery	E-mail	
X		CATHERINE P. AWAKUNI EXECUTIVE DIRECTOR DEPARTMENT OF COMMERCE AND CONSUMER AFFAIRS DIVISION OF CONSUMER ADVOCACY P. O. Box 541 Honolulu, Hawaii 96809 (Catherine.P.Awakuni@dcca.hawaii.gov) (Jon.S.Itomura@dcca.hawaii.gov) (mbrosch@utilitech.net) (scarver@utilitech.net)
	X	RANDALL J. HEE, P.E. PRESIDENT AND CEO KAUAI ISLAND UTILITY COOPERATIVE 4463 Pahe'e Street, Suite 1 Lihue, Hawaii 96766-2000 (rhee@kiuc.coop)
	X	TIMOTHY BLUME MICHAEL YAMANE KAUAI ISLAND UTILITY COOPERATIVE 4463 Pahe'e Street, Suite 1 Lihue, Hawaii 96766-2000 (tblume@kiuc.coop)

Hand Delivery	E-mail	
X		KENT D. MORIHARA, ESQ. KRIS N. NAKAGAWA, ESQ. RHONDA L. CHING, ESQ. MORIHARA LAU & FONG LLP 841 Bishop Street, Ste. 400 Honolulu, HI 96813 (kmorihara@moriharagroup.com) Attorneys for KAUAI ISLAND UTILITY COOPERATIVE
	X	WARREN S. BOLLMEIER II PRESIDENT HAWAII RENEWABLE ENERGY ALLIANCE 46-040 Konane Place, No. 3816 Kaneohe, HI 96744 (wsb@lava.net)
	X	CARL FREEDMAN HAIKU DESIGN & ANALYSIS 4234 Hana Highway Haiku, Hawaii 96708 (jcfm@hawaiiantel.net)
	X	GERALD A. SUMIDA, ESQ. TIM LUI-KWAN, ESQ. NATHAN C. NELSON, ESQ. CARLSMITH BALL LLP ASB Tower, Suite 2200 1001 Bishop Street Honolulu, Hawaii 96813 (gsumida@carlsmith.com) (tlui-kwan@carlsmith.com) (nnelson@carlsmith.com) Attorneys for HAWAII HOLDINGS, LLC, dba FIRST WIND HAWAII
	X	MIKE GRESHAM HAWAII HOLDINGS, LLC, dba FIRST WIND HAWAII 33 Lono Avenue, Suite 380 Kahului, Hawaii 96732 (mgresham@hawaii.rr.com)

Hand Delivery	E-mail	
	X	DEBORAH DAY EMERSON, ESQ. GREGG J. KINKLEY, ESQ. DEPUTY ATTORNEYS GENERAL DEPARTMENT OF THE ATTORNEY GENERAL STATE OF HAWAII 425 Queen Street Honolulu, Hawaii 96813 (gregg.j.kinkley@hawaii.gov) Attorneys for the DEPARTMENT OF BUSINESS, ECONOMIC DEVELOPMENT, AND TOURISM
	X	THEODORE PECK DEPARTMENT OF BUSINESS, ECONOMIC DEVELOPMENT, AND TOURISM State Office Tower 235 South Beretania Street, Room 501 Honolulu, Hawaii 96813 (tpeck@dbedt.hawaii.gov)
	X	ESTRELLA SEESE DEPARTMENT OF BUSINESS, ECONOMIC DEVELOPMENT, AND TOURISM State Office Tower 235 South Beretania Street, Room 501 Honolulu, Hawaii 96813 (eseese@dbedt.hawaii.gov)
	X	MARK DUDA PRESIDENT HAWAII SOLAR ENERGY ASSOCIATION P. O. Box 37070 Honolulu, Hawaii 96737 (mark@suntechhawaii.com)

Hand Delivery	E-mail	
	X	DOUGLAS A. CODIGA, ESQ. SCHLACK ITO LOCKWOOD PIPER & ELKIND Topa Financial Center 745 Fort Street Mall, Suite 1500 Honolulu, Hawaii 96813 (dcodiga@sil-law.com) Attorney for BLUE PLANET FOUNDATION

DATED: Honolulu, Hawaii, September 29, 2009.

THOMAS W. WILLIAMS, JR.
PETER Y. KIKUTA
DAMON L. SCHMIDT

Attorneys for
HAWAIIAN ELECTRIC COMPANY, INC.
HAWAII ELECTRIC LIGHT COMPANY, INC., and
MAUI ELECTRIC COMPANY, LIMITED

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